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Control of Utility Boiler and Gas Turbine Pollutant Emissions by Combustion Modification - Phase I

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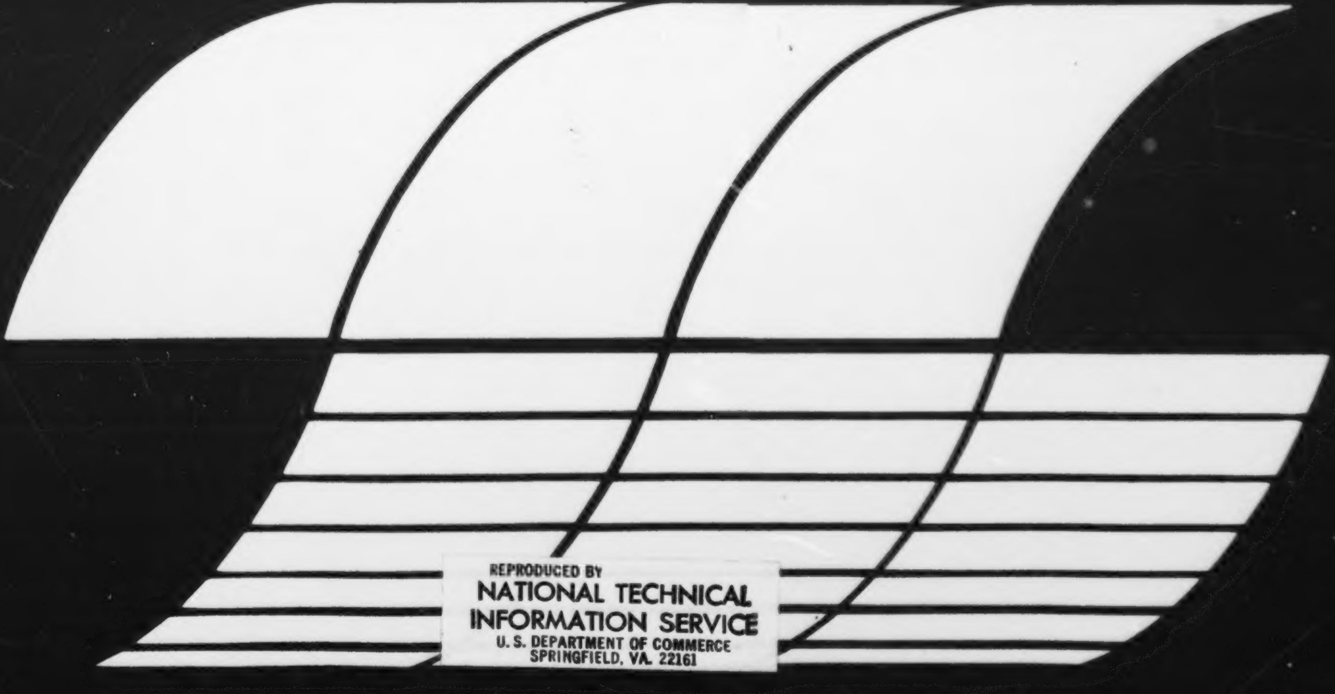

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16. ABSTRACT The report gives results of a field study to assess the applicability of combustion modification techniques to control NOx and other pollutant emissions from utility boilers and gas turbines without causing deleterious side effects. Comprehensive, statistically designed tests were used to evaluate the effect of combustion modifications. The most extensively studied combustion modification for utility boiler applications was staged firing at low excess air, which can reduce NOx emissions by up to about 50%, based on the results of short term tests. With emphasis on NOx emission control for coal-fired utility boilers, special attention was paid to the determination of potentially adverse side effects: increased combustible emissions, unwanted changes in particulate mass loading and size distribution, reduced boiler efficiency, increased furnace slagging and tube wall corrosion, and flame problems. Short term tests indicate that staged combustion may be applied to coal-fired utility boilers. The extent of furnace tube wall corrosion and slagging could not be determined conclusively, based on the results of 300-hour corrosion probing runs under low NOx and baseline operating conditions. For this reason, a long term furnace tube wall corrosion test of at least 6 months duration was initiated on a 500 MWe front-wall-fired boiler at Gulf Power Company's Crist Station.

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SUMMARY

Exxon Research and Engineering Company (ER&E) has been performing a continuing field study on the application of combustion modification to control pollutant emissions from power generation combustion sources. This program, jointly sponsored by EPA (Contract No. 68-02-1415) and EPRI (Project No. 200), was conducted with the cooperation of equipment manufacturers and equipment operators. Measurements of gaseous emissions, particulate mass, particulate size distribution, accelerated corrosion, and slagging tendency, and boiler efficiency were made using ER&E's mobile sampling/analytical van.

The major emphasis in this program was placed upon combustion modification of coal-fired boilers. In addition, field testing of mixed-fuel fired boilers, waste fuel-fired boilers, gas turbines and stationary internal combustion engines is also included within the scope of this program.

Seven coal-fired boilers, including two with mixed-fuel firing (coal-oil, coal-gas) capabilities and a gas turbine were tested during the period of performance between July 1974 and December 1975 under this contract. Among the units tested, four coal-fired boilers were equipped with special NO_x emission reduction equipment. Three of the Combustion Engineering designed boilers tested have overfire air ports and a Babcock and Wilcox designed boiler has been retrofitted with that company's "low NO_x", dual register, compartimentalized windbox coal burners. A Foster Wheeler boiler designed to operate with a wet bottom at low loads was also tested for possible side effects under "low NO_x" operation. The three-phase test programs conducted on most of these units consisted of, first, a statistically designed short period test run to determine baseline and minimum NO_x emission capability of the unit, second, a one or two day sustained run under "low NO_x" operation to determine if potential operating problems arise and third, a 300-hour sustained run under baseline and "low NO_x" conditions to check on other potential adverse side effects such as increased corrosion and slagging problems, loss in boiler efficiency and changes in particulate emissions.

Several key findings were determined from an analysis of the gaseous emission data. The B&W boiler retrofitted with the new burners emitted 36% less NO_x under normal firing and over 50% less NO_x under full load, staged firing operation than was emitted from an identical boiler equipped with conventional burners. Tangentially fired boilers equipped with overfire air ports emitted about 20% less NO_x than similar boilers when tested under normal firing operation. Modified firing using overfire air ports and low excess air resulted in an average of over 40% additional reduction in NO_x emissions at full load, for a reduction of over 50 percent over boilers not equipped with overfire air ports. Mixed fuel-fired boiler NO_x emission levels increased as the % of coal in the coal-oil or coal-gas mixture increased, but not linearly. NO_x emissions from a 50 MWe electrical output, gas turbine were about 219 ng/J (375 ppm on a 3% O_2 basis) at full load, 234 ng/J (400 ppm) at peak load, with reductions to about 190 ng/J and 146 ng/J (325 and 250 ppm) at 50% and 20% of full load, respectively. (Note that all ppm emission values given in this report are corrected to a 3% O_2, dry basis and all megawatt values are on an electrical output basis, MWe).

Only relatively minor differences have been observed in particulate mass loadings between "low NO_x" and baseline firing conditions. Unburned carbon in the fly-ash, which was observed to increase in previous studies (especially on front wall and horizontally opposed fired boilers) was found to decrease on some of the boilers tested in this program. Particle size distribution, which could affect electrostatic precipitator collection efficiency, was found to be very similar for "low NO_x" operation and for baseline conditions. As in previous studies, no major changes in boiler efficiency have been observed as a result of "low NO_x" operation.

In 300-hour sustained runs, no major differences in corrosion rates of corrosion coupons have been observed for low NO_x firing compared to normal operation. However, long term tests measuring actual furnace wall tube wastage are needed to settle this important question.

1. INTRODUCTION

Since 1970, Exxon Research and Engineering Company (ER&E) has been conducting field studies under EPA sponsorship on the application of combustion modification techniques to control pollutant emissions from utility boilers. The emphasis in these studies has been on controlling NO_x emissions without causing adverse side-effects.

Under EPA Contract No. CPA 70-90 (1), significant reductions of NO_x were achieved for gas and oil-fired boilers using combustion modification techniques in field testing of limited duration, without attempting to optimize the technology. The principal modifications investigated consisted of minimizing excess air, staged introduction of the combustion air, flue gas recirculation, varying boiler load, and varying air preheat temperature. Also, as part of this study, it was possible to achieve significant reductions in NO_x emissions for two of the seven coal-fired boilers tested, through the combination of low excess air with staged firing.

Because of the difficulty of controlling NO_x emissions from coal-fired boilers, in the subsequent EPA-sponsored ER&E study (Contract No. 68-02-0227) (2) the emphasis shifted to a more detailed investigation of emission control for coal-fired utility boilers, again in cooperation with boiler owner-operators and manufacturers. These field studies, on twelve coal-fired units representative of the current design practices of the major U.S. boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler, and Riley-Stoker), have produced very promising results. It was possible to achieve reductions in NO_x emissions ranging between about 30% and 50%, without apparent adverse side-effects. In addition to gaseous emissions measurements, the studies included particulate mass loading and unburned combustible measurements, accelerated furnace corrosion probing, determination of boiler efficiency, and observations on changes in boiler operability with particular attention to slagging, fouling, and flame problems.

Based on the encouraging results of the above work, the Environmental Protection Agency and the Electric Power Research Institute decided to jointly fund the present ER&E field study. The scope of the work was broadened to determine the effects of combustion modification techniques on the control of pollutant emissions and on the performance of fossil fuel fired power generation equipment. In this field program, the combustion equipment selected for study included coal-fired, mixed-fuel fired and waste fuel-fired boilers to be studied, in addition to short-term tests on stationary gas turbine and I.C. engine equipment. The principal continuing emphasis in this work remained on coal-fired utility boilers. All but one of the coal-fired boilers tested in this study had dry-bottom furnaces.

In the field studies detailed in this report, the combustion equipment selected was tested in cooperation with the owner-operators and the manufacturers. The effectiveness of equipment modifications designed to provide NO_x emission control, such as coal-fired boilers constructed with overfire air ports, and the use of low NO_x emitting improved burner design were explored. Potential adverse side-effects of combustion modifications were studied in more detail than previously. Thus, in addition to the gaseous emission measurements (including pollutants, stable combustion products and unburned combustibles), particulate mass and size distribution measurements were made under both normal and low NO_x modes of boiler operation.

As in the earlier field studies, the effect of combustion modifications on boiler efficiency and operability was determined. Special attention was paid to the demonstration of potential furnace fireside tube wall corrosion problems that may result from staged firing with coal, i.e., with parts of the boiler operated under fuel rich, reducing conditions. For this purpose, 300-hour corrosion probe runs with air-cooled coupons were made under both low NO_x and baseline firing conditions in the boilers studied.

Under Contract No. 68-02-1415, this final report on Phase I will be followed by a final report on Phase II of the program. The final report on Phase II will include summary tables from this report plus test data on additional pulverized coal-fired boilers (Crist No. 7, Sewaren No. 5, Cooper No. 2 and Comanche No. 2), additional gas turbines (Wharton No. 42, and Wharton No. 43). A waste fuel supplemented coal fired boiler and a pulverized coal-fired boiler utilizing a slag reducing additive may also be included. Trace species pollutant data determined from the newly developed Source Assessment Sampling System (SASS) train will also be covered in the final report on Phase II. A separate, Data Supplement containing detailed raw pollutant emission and operating data covering all units tested will be issued following completion of this program. In addition, two Guideline publications will be issued: one for utility operators, and a second for utility boiler designers. Furthermore, a report will be issued which will describe results of a comprehensive, long-term fireside tube wall corrosion study while operating under baseline and low NO_x conditions.

2. FIELD STUDY PLANNING AND PROCEDURES

This section discusses the major steps involved in field study planning and the testing methods used to obtain emission, corrosion and performance measurements. Field study planning steps included selection of representative power generation equipment (with participation of EPA, EPRI, equipment manufacturers and equipment operators) and designing an effective test program strategy. Methods of gaseous emission testing were similar to those developed and applied in ER&E's "Systematic Field Study" (1). Particulate sampling, corrosion probing and performance measurements were also based on methods used in ER&E's previous field studies (2). Boilers firing coal, coal-oil and coal-gas mixed fuel were tested, as was an oil-fired power generating gas turbine.

2.1 SELECTION OF POWER GENERATION COMBUSTION EQUIPMENT

This program provides for the testing of utility boilers (coal-fired, mixed fossil-fuel fired and waste-fuel fired) utility sized gas turbines and a large, stationary IC engine. This report covers the field tests completed on five coal-fired boilers, two mixed-fuel (coal-oil and coal-gas) fired boilers and an oil-fired gas turbine. No waste-fuel fired utility boiler could be located for testing during the period of performance covered by this report. Also, testing of a stationary I.C. engine used for power generation was deferred to a later date to permit the completion of the boiler tests.

The successful selection of boilers representing current design practices was the result of a cooperative planning effort by Exxon Research, EPA, EPRI and boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler and Riley Stoker). The process of developing boiler selection criteria, reviewing boiler manufacturers' candidate boilers meeting the criteria, selecting a tentative list of boilers for detailed field meetings and final selection and scheduling of test programs was described in a previous report (2).

Design factors were the prime consideration in selecting boilers in the current field test program after other criteria such as size, operating flexibility, boiler measurement and control capability had been met. Boilers representing the current design practices of all four utility boiler manufacturers were sought for this study. Coal-fired boilers equipped with overfire air ports or with new burners installed for NO_x emission control were of special importance to compare the emission control performance of such units to those operated under modified conditions but without making the NO_x control capability an integral feature of the equipment. The cooperation of boiler operators was secured to use three tangentially fired (2 coal, 1 coal-gas mixed fuel) boilers with overfire air ports and a wall fired boiler retrofitted with special low NO_x burners. Field testing of an operating front-wall, coal-fired utility boiler equipped with overfire air ports was attempted but could not be arranged with its owner-operator.

The design and operating features of the seven coal or mixed-fuel fired boilers tested in the current program are summarized in Table 2-1. Four of these boilers are tangentially fired (ranging in size from 130 MWe to 800 MWe) and three of them are wall fired (a rear wall fired 125 MWe unit, a front wall fired, 290 MWe unit, and a horizontally opposed fired 270 MWe capacity unit). As discussed earlier, these boilers have been selected for field studies at the recommendation of their respective manufacturers as representative of current design practices and/or because of specially designed NO_x reduction capabilities. Tables 2-2 and 2-3 present summaries of coal and oil fired boilers tested in a previous program (2) for comparison purposes.

2.2 TEST PROGRAM STRATEGY

The up-to-date, comprehensive information obtained in field meetings provided the necessary data to develop detailed, run-by-run proposed test program plans for review by the sponsors and the cooperating parties. Each test program, tailored to take full advantage of the particular combustion control flexibility of each boiler, was comprised of three phases: (1) short test-period runs, (2) a 1-3 day sustained "low NO_x" run, and (3) 300-hour sustained "low NO_x" and normal operation runs. Thus, the strategy used for field testing coal-fired boilers consisted of first, defining the optimum operating conditions for NO_x emission control, without apparent adverse side-effects in short-term statistically designed test programs. Second, the boiler was operated for 1-3 days under the "low NO_x" conditions determined during the optimization phase, for assessing boiler operability problems. Finally, where possible, sustained 300-hour runs were made under both baseline and modified ("low NO_x") operating conditions. During this period, air-cooled carbon steel coupons were exposed on corrosion probes in the vicinity of furnace water tubes, to determine through accelerated corrosion tests whether operating parts of the boiler under the reducing conditions associated with staged firing results in increased furnace tube wall corrosion rates. Particulate samples were obtained under both baseline and "low NO_x" conditions. Engineering information on boiler operability, such as flame instability, impingement and slagging problems, and data on boiler performance were obtained.

Statistical principles (as discussed in more detail in a previous report (1)) provided practical guidance in planning the Phase I test programs, e.g., how many, and which test runs to conduct, as well as the proper sequence in which they should be run. These procedures allow valid conclusions to be drawn from analysis of data on only a small fraction of the total possible number of different test runs that could be made in principle, resulting in increased productivity of the research work. Our earlier studies (2) describe in detail an example of these principles applied to field testing of a wall-fired boiler.

Statistical principles were also used extensively in the analysis of emission data recorded from each test run. For example, least squares regression analysis was used to obtain valid estimates of the relationship between NO_x emission levels and operating variables, such as excess air level. These techniques provide objective, uniform methods of analysis that can be easily verified, provide the basis for efficient assessment of outlier data, and limit the risk of drawing false conclusions.

TABLE 2-1

SUMMARY OF COAL AND MIXED FUEL FIRED BOILERS TESTED

	Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	Fuel(c) Burned	MCR (MWe)	No. of Burners	Test Variables	No. of Test Runs	NO_x Emissions Baseline ppm (lb/10^6 BTU) (i)	NO_x Emissions Low NO_x ppm (lb/10^6 BTU) (i)	% NO_x(h) Reduction
1.	Tennessee Valley Authority	Widows Creek - 5	B&W	RW	C	125	16	4	31(d)	597 (0.81)	468 (0.64)	22
2.	Southern Electric Generating Company	E. C. Gaston - 1	B&W	HO(e)	C	270	18	5	37(d)	389 (0.53)	278 (0.38)	29
3.	Alabama Power Company	Barry - 2	CE	T(f)	CG	130	16	6	38	341 (0.46)	189 (0.26)	45
4.	Potomac Electric Power Company	Morgantown - 1	CE	T	CO	575	40	5	27	552 (0.75)	403 (0.55)	27
5.	Salt River Project	Navajo - 2	CE	T(f)	C	800	56	4	36(d)	492 (0.67)	282 (0.38)	43
6.	Public Service Company of Colorado	Comanche - 1	CE	T(f)	C	350	20	4	30(d)	417 (0.57)	261 (0.35)	37
7.	Public Service Electric and Gas Company	Mercer - 1	FW	FW(g)	C	270	24	4	33(d)	1383 (1.88)	876 (1.19)	37
	Average of Coal Fired Boilers								33	656 (0.89)	433 (0.59)	34

(a) B&W - Babcock and Wilcox, CE - Combustion Engineering, FW - Foster Wheeler

(b) RW - rear wall, HO - horizontally opposed, T - tangential, FW - front wall

(c) C - coal, C-G - coal-gas mixed, C-O - coal-oil mixed

(d) Particulate and corrosion probe tests performed on these boilers

(e) Special low NO_x emission burners

(f) Overfire air ports

(g) Wet bottom furnace

(h) % NO_x reduction at full or near full load

(i) PPM NO_x - 3% O_2, dry basis

TABLE 2-2

SUMMARY OF COAL-FIRED BOILERS TESTED IN A PREVIOUS EXXON FIELD TEST PROGRAM (2)

	Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	MCR (MW)	No. of Burners	Test Variables	No. of Test Runs	NO_x Emissions		
									Baseline ppm (lb/10^6 BTU) (f)	Low NO_x ppm (lb/10^6 BTU) (f)	% NO_x(e) Reduction
1.	Tennessee Valley Authority	Widows Creek - 6	B&W	RW	125	16	4	41 (c)	634 (0.84)	379 (0.50)	40
2.	Gulf Power	Crist - 6	F-W	FW	320	16	4	22(c)	832 (1.11)	550 (0.73)	34
3.	Georgia Power	Harllee Branch - 3	B&W	HO	480	40	4	51(c)(d)	711 (0.95)	463 (0.62)	35
4.	Arizona Public Service	Four Corners - 4	B&W	HO	800	54	5	26(c)(d)	935 (1.24)	488 (0.65)	48
5.	Utah Power and Light	Naughton - 3	CE	T	330	20	6	26(c)(d)	531 (0.71)	219 (0.29)	59
6.	Alabama Power	Barry - 4	CE	T	350	20	7	46(c)(d)	415 (0.55)	273 (0.36)	34
7.	Alabama Power	Barry - 3	CE	T	250	48	4	8	410 (0.55)	310 (0.41)	24
8.	Tampa Electric	Big Bend - 2	RS	Turbo	350	24	4	14	600 (0.80)	398 (0.53)	34
9.	Central Illinois Light	E. D. Edwards - 2	RS	FW	256	16	4	19	703 (0.93)	359 (0.48)	49
10.	Basin Electric	Leland Olds - 1	B&W	HO	218	20	3	13	569 (0.76)	375 (0.50)	33
11.	Pacific Power and Light	Dave Johnston - 2	B&W	FW	105	18	3	14	454 (0.60)	214 (0.28)	53
12.	Pacific Power and Light	Dave Johnston - 4	RW	T	348	28	7	6	434 (0.53)	384 (0.51)	12
	Average of Coal Fired Boilers							24	602 (0.80)	368 (0.49)	39

(a) B&W - Babcock and Wilcox
CE - Combustion Engineering
F-W - Foster Wheeler Energy
RS - Riley Stoker

(b) RW - Rear Wall
FW - Front Wall
HO - Horizontally Opposed
T - Tangential
Turbo - Turbo-Furnace

(c) Particulate tests performed on these boilers

(d) Corrosion probe tests performed on these units

(e) % NO_x reduction at full or near full load

(f) PPM NO_x - 3% O_2, dry basis

TABLE 2-3

SUMMARY OF OIL-FIRED BOILERS TESTED IN A PREVIOUS EXXON FIELD PROGRAM (2)

									NO$_x$ Emissions		
	Boiler Operator	Station and Boiler No.	Boiler Mfr.(a)	Type of Firing(b)	MCR (MWe)	No. of Burners	Test Variables	No. of Test Runs	Baseline ppm (lb/10^6 BTU) (c)	Low NO$_x$ ppm (lb/10^6 BTU) (c)	% NO$_x$(d) Reduction
1.	Atlantic City Electric	Deepwater - 3	B&W	FW	55	6	2	8	142 (0.19)	118 (0.16)	17
2.	Atlantic City Electric	Deepwater - 5	B&W	FW	55	6	2	4	221 (0.29)	175 (0.23)	21
3.	Atlantic City Electric	Deepwater - 8	B&W	FW	83	16	3	25	246 (0.33)	124 (0.16)	50
4.	Atlantic City Electric	Deepwater - 9	CE	T	23	6	2	7	286 (0.38)	101 (0.13)	65
5.	Atlantic City Electric	B. L. England - 1	B&W	Cy	136	3	2	7	441 (0.59)	313 (0.42)	29
6.	Atlantic City Electric	B. L. England - 2	B&W	Cy	168	4	1	2	361 (0.48)	303 (0.42)	16
	Average of Oil-Fired Boilers							9	283 (0.37)	189 (0.25)	33

(a) B&W - Babcock and Wilcox, CE - Combustion Engineering

(b) FW - front wall, T - tangential, Cy - cyclone

(c) PPM NO$_x$ - 3% O$_2$, dry basis

(d) % NO$_x$ reduction at full or near full load

2.3 GASEOUS SAMPLING AND ANALYSIS

The mobile sampling and analytical system used in this study to obtain reliable gaseous emission data from field tests was described in detail in previous reports (1,2) and, for convenience, is included in Appendix E. A schematic diagram of the revised sampling system used in this program is provided in Figure 2-1. The gaseous species analyzed are also shown on this diagram. Table 2-2 tabulates the instruments contained in the ER&E Sampling and Analytical Van according to manufacturer, operating technique employed, and measurement range capabilities. This system has been used in all of our preceding field testing to obtain reliable data with a minimum of operating difficulties.

A major consideration in obtaining reliable gaseous emission data is to insure that the sample gas is virtually moisture free. Moisture in the sample gas can influence the readings obtained by some of the analytical monitoring instrumentation, for example, moisture is an unwanted interference with NO, CO_2 and CO nondispersive infrared analyzers. This problem is avoided effectively in the sampling system used by passing the sample gases through a refrigerated water trap coil. Recently, permeation-type drying tubes* (Permatubes) have become available for removing moisture in gas sampling systems without changing the concentrations of other gaseous species. For this reason, Permatube driers were adapted to our sampling train as an addition to the refrigerated traps to insure a maximum drying capability for the gaseous emission sampling system. This system has proven to be effective in obtaining dry sample gases.

Concurrent with the present program, Exxon Research and Engineering Company conducted an investigation under contract to EPA (Contract No. 68-02-1722) to "Determine the Magnitude of the Stratification of Gases in the Ducts of Fossil Fuel Fired Power Plants" (3). The results of this investigation showed that stratification of the gases in the ducts indeed does exist and that reliable "average" flue gas concentrations can be obtained only by multiple probe sampling of the inner 50% of the duct. Also, average emission data obtained in this manner are within plus or minus 10 percent of the actual concentration values in adjacent ducts on the same boiler, with the possible exception of oxygen, because the concentration in the ducting is influenced by air infiltration.

The findings of our boiler duct stratification study verify the design principles utilized by the ER&E sampling-analytical system for obtaining representative gaseous emission data. In the ER&E system, samples are taken from zones of "equal areas" in the flue gas ducts. At least two probes are installed in each flue gas duct, or a minimum of four are used when there is only one large flue gas duct on the boiler. Each of the probes consists of three stainless steel sampling tubes (short, medium and long) reaching to the mid-point of zones of equal area through the depth of the duct. Thus, a minimum of six sampling points per duct, or 12 per boiler are provided, assuring that representative gas samples are obtained.

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* Manufactured by Perma Pure, Inc., Oceanport, N. J.

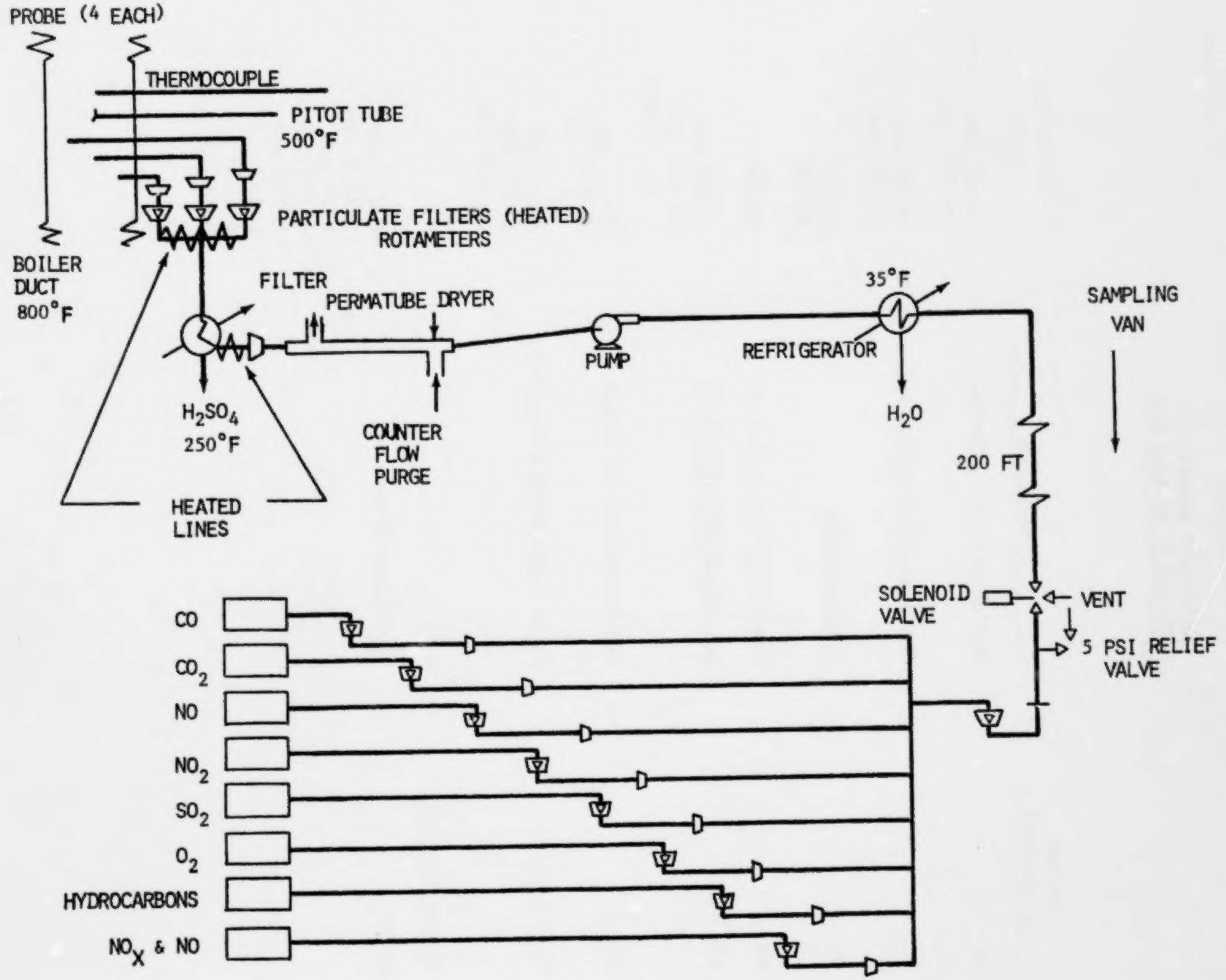
PROBE (4 EACH)
THERMOCOUPLE
PITOT TUBE
500°F
PARTICULATE FILTERS (HEATED)
ROTAMETERS
BOILER
DUCT
800°F
FILTER
PERMATUBE DRYER
H_2SO_4
250°F
COUNTER
FLOW
PURGE
HEATED
LINES
PUMP
35°F
REFRIGERATOR
H_2O
SAMPLING
VAN
200 FT
SOLENOID
VALVE
VENT
5 PSI RELIEF
VALVE
CO
CO_2
NO
NO_2
SO_2
O_2
HYDROCARBONS
NO_X & NO

Figure 2-1. Exxon Research transportable sampling and analytical system.

TABLE 2-4

CONTINUOUS ANALYTICAL INSTRUMENTS IN ER&E VAN

Beckman Instruments	Technique	Measuring Range
NO	Non-dispersive Infrared	0-400 ppm 0-2000 ppm
NO_2	Non-dispersive ultraviolet	0-100 ppm 0-400 ppm
O_2	Polarographic	0-5% 0-25%
CO_2	Non-dispersive infrared	0-20%
CO	Non-dispersive infrared	0-200 ppm 0-1000 ppm 0-23,600 ppm
SO_2	Non-dispersive infrared	0-600 ppm 0-3000 ppm
Hydrocarbons	Flame ionization detection	0-10 ppm 0-100 ppm 0-1000 ppm
Thermo Electron		
NO/NO_x	Chemiluminescence	0-2.5 ppm 0-10.0 ppm 0-25 ppm 0-100 ppm 0-250 ppm 0-1000 ppm 0-2500 ppm 0-10,000 ppm

A complete range of calibration gas cylinders in appropriate concentrations with N2 purge and zero gas for each analyzer is installed in the system. The instruments are calibrated daily before each test, and also in-between tests if necessary, to assure reliable and accurate results.

Two Joy Manufacturing Company, and two Aerotherm Acurex High Volume EPA type particulate sampling trains designed according to EPA Method No. 5 (4) were used to obtain particulate mass loading data. These trains were modified to incorporate Brink multi-stage cascade impactors in the heated sampling box for the determination of particle size distribution. This arrangement permits particle size distribution determinations on the outside of the boiler duct under isokinetic sampling conditions.

2.4 PARTICULATE SAMPLING

To control NO_x emissions, combustion modification techniques are used at less intense combustion conditions than those corresponding to conventional firing methods. Combustion modifications such as lowering and optimizing excess air levels, staging the combustion process and re-adjustment of burner dampers to decrease the air supplied to the flame zone may lead to carbon burnout problems reflected in changes in particulate emissions. Lowering excess air tends to limit the amount of oxygen available for completion of the combustion process. This factor is expected directionally to increase the probability of burnout problems. Staging the combustion pattern, where the majority of the burners are operated at sub-stoichiometric air supply conditions for NO_x emission control, and the remaining air is introduced either through inactive burners or overfire air ports to complete the combustion process, is expected to have similar effects. Since with staged combustion the amount of available oxygen is limited in the burner zone, the flames are lengthened, and turbulence may be reduced, resulting in slower diffusive mixing of air and fuel. Thus, staging the combustion pattern may also increase unburned combustibles. Beyond the issue of combustibles (soot particulates and unburned carbon), modifications to the combustion process for NO_x emission control may also affect the quantity, size distribution and composition of the particulate matter emitted from the boiler.

To obtain information on the effect of combustion modifications on particulate emissions, the field studies included the measurement of particulate mass loading and flyash particle size distribution upstream of the particulate collector device of pulverized coal fired utility boilers. Measurements of total mass loading and particle size distribution were made under baseline and optimized low NO_x operating conditions to determine the extent of adverse effects of staged firing and other NO_x emission reduction techniques. Flyash was analyzed for unburned carbon content for use in these comparisons. Such information is needed to evaluate the impact of potential changes in particulates on electrostatic precipitator performance and to determine the effect of combustion modifications on trace species emissions.

2.5 FURNACE FIRESIDE TUBE WALL CORROSION PROBE MEASUREMENTS

Under certain conditions, pulverized coal-fired boilers are subject to wastage of the furnace tubes. Normal corrosion occurs in oxidizing atmospheres due to the corrosive effect of iron alkali sulfate attack on the tube metal surface. However, under fuel-rich reducing conditions, corrosion of the furnace tubes may be accelerated (particularly with high sulfur, high iron content coals) due to increased slagging on the tube surface and penetration of iron sulfide into metal surfaces. Under normal firing conditions this type of corrosion is most likely to occur in areas where a localized reducing environment might exist adjacent to the midpoint of furnace sidewalls near burner elevations where flame impingement might occur. To counteract such effects, normal boiler operating practice is to increase the excess air level so that an oxidizing atmosphere prevails at these locations, and to increase the fineness of pulverization, so that the oxidation of the pyrites in the coal is completed before these species can come into contact with the furnace wall tube surface. For new boilers, an improved design feature consists of increasing the separation between the burners and the sidewalls, thus minimizing potential flame impingement problems.

The most effective combustion modifications to control NO_x emissions from coal-fired boilers are staged combustion and low excess air firing, i.e., conditions that are potentially conducive to furnace tube wall corrosion. The need to investigate the effects of staged combustion on furnace tube corrosion was recognized and preliminary measurements were made in earlier studies by Exxon Research and Engineering Company under EPA Contract No. 68-02-0227. Details and results of these studies were reported previously (2).

In the earlier program, the approach used for measuring corrosion rates was to expose corrosion coupons installed on the end of probes. The probes were inserted into available openings located near "vulnerable" areas of the furnace under both baseline and low NO_x firing conditions. Coupons were fabricated of SA 192 carbon steel, the same material as that currently used for furnace wall tubes. Exposure of the coupons for 300 hours at elevated temperatures of 742 K (875°F) (higher than normal furnace tube wall temperature of about 589 K (600°F) was chosen in order to deliberately accelerate corrosion so that measurable values could be obtained. Coupons were also mildly acid pickled to remove the existing oxide coating prior to exposure to eliminate potential differences caused by surface conditions. The conclusion of these earlier corrosion probing tests was that no major differences in corrosion rates could be found between coupons exposed to low NO_x firing conditions compared to coupons exposed under normal boiler operating conditions. Coupon corrosion rates were, however, considerably higher under both baseline and low NO_x conditions than those corresponding to normal furnace tube wastage rates because of the accelerated nature of these corrosion probing tests.

The approach used for the measurement of furnace tube corrosion rates in the current program was similar to that of the earlier work, but with several significant differences. First, corrosion coupons were no longer mildly acid pickled (which removed the protective iron oxide film) but instead, were dipped in acetone and air dried prior to weighing to remove any oil deposited during machining. Second, coupon temperatures were maintained during exposure in the boiler at approximately the metal temperatures of the furnace wall tubes in an effort to more closely approximate actual furnace conditions. Thus, instead of being operated at 742 K, as in the prior work, the coupons were kept at 589 K. Third, three coupons were installed on each probe, to increase the amount of data obtained compared with only two coupons per probe in the prior program. Time of exposure (300 hours) was held the same as in the previous studies so that the results of the present corrosion probing runs could be compared to the earlier work.

Figures 2-2 and 2-3 show details of the corrosion probes used in the present and previous studies. The design of these corrosion probes was based on information supplied by Combustion Engineering, with appropriate modifications for this work. Essentially, the design consists of a "pipe within a pipe", where the cooling air from the plant air supply is admitted to the ring-shaped coupons exposed to furnace atmospheres at one end of the probe, through a 19 mm (3/4-inch) stainless steel tube roughly centered inside of the coupons. The amount of cooling air is automatically controlled to maintain the desired set-point temperature of 603-672 K (625-750°F) for the coupons. The cooling air supply tube is axially adjustable with respect to the corrosion coupons, so that temperatures of coupons may be balanced. To simplify the pictorial presentation, the thermocouples mounted in each coupon are not shown in Figures 2-2 and 2-3. Normally, one thermocouple is used for controlling and the other one is used for recording temperatures. Also, as noted above, a third coupon is used on the probe (between the coupons with the thermocouples) which is not shown in Figure 2-3. The cooling air travels backwards along the 63.5 mm (2-1/2-inch) extension pipe and discharges outside of the furnace. Thus, the cooling air and the furnace atmosphere do not mix at the coupon location.

2.6 BOILER EFFICIENCY

The application of staged combustion for NO_x emission control is based on fuel rich operation of a number of burners. This results in less intense combustion conditions which may increase carbon burnout problems. Thus, because this mode of boiler operation may increase the amount of unburned combustibles, there may be an adverse impact on boiler efficiency. However, potential efficiency losses may be compensated by the increase in efficiency resulting from reduced stack losses under such conditions. To determine the effect of combustion modification techniques applied for NO_x control on boiler efficiency, particulate mass loading tests were run for each boiler under baseline and low NO_x operating conditions and the fly ash samples were analyzed for unburned carbon. Boiler efficiency was then calculated, using the ASME Abbreviated Efficiency Test based on the heat loss method, and the results were compared to evaluate the effects of low NO_x firing on efficiency. The results obtained are presented and discussed in Section 3.4.

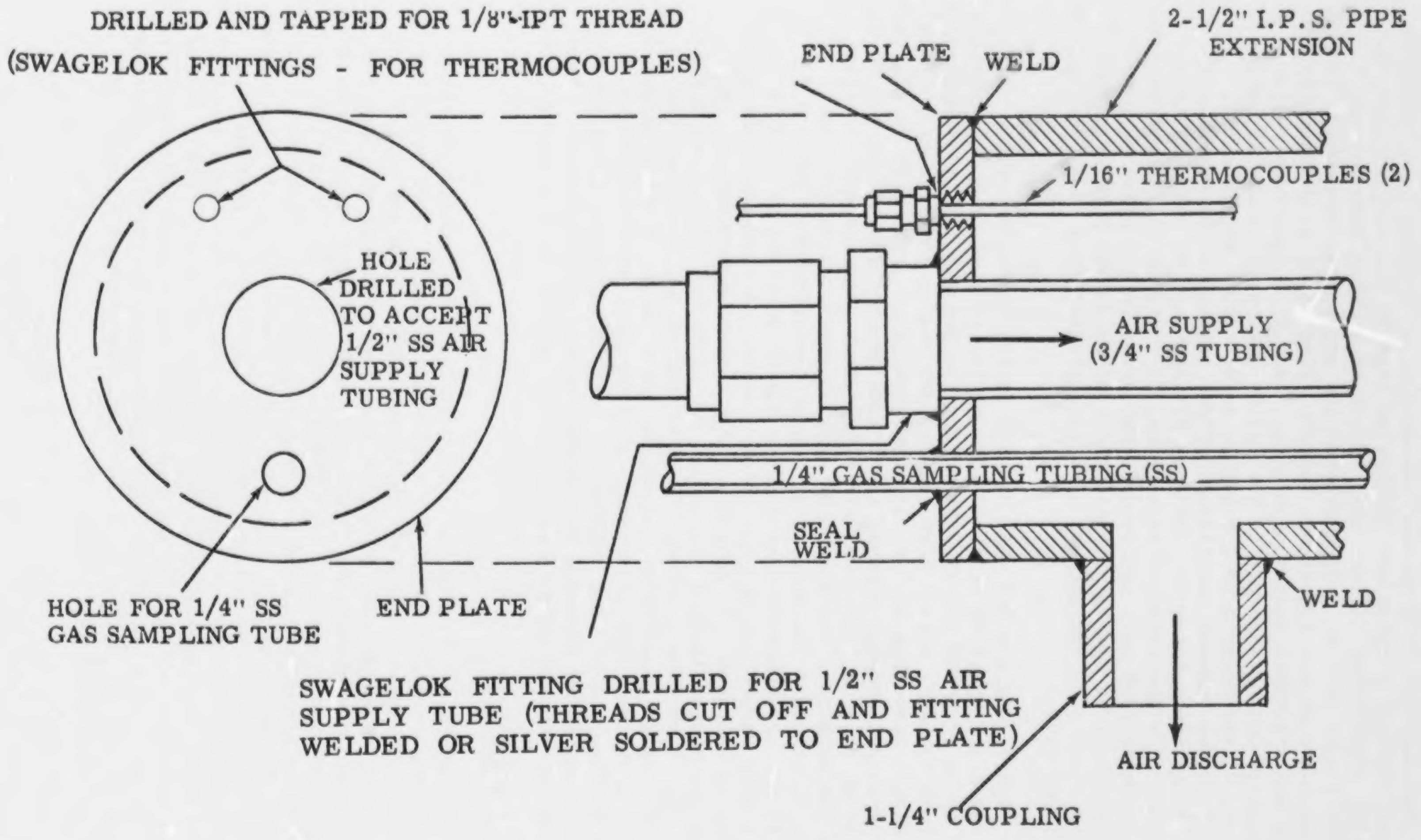
DRILLED AND TAPPED FOR 1/8"-IPT THREAD
(SWAGELOK FITTINGS - FOR THERMOCOUPLES)
END PLATE
WELD
2-1/2" I.P.S. PIPE EXTENSION
1/16" THERMOCOUPLES (2)
HOLE DRILLED TO ACCEPT 1/2" SS AIR SUPPLY TUBING
AIR SUPPLY (3/4" SS TUBING)
1/4" GAS SAMPLING TUBING (SS)
SEAL WELD
HOLE FOR 1/4" SS GAS SAMPLING TUBE
END PLATE
WELD
SWAGELOK FITTING DRILLED FOR 1/2" SS AIR SUPPLY TUBE (THREADS CUT OFF AND FITTING WELDED OR SILVER SOLDERED TO END PLATE)
AIR DISCHARGE
1-1/4" COUPLING

Figure 2-2. Corrosion probe, detail of 2½" extension pipe and end plate (outside of furnace).

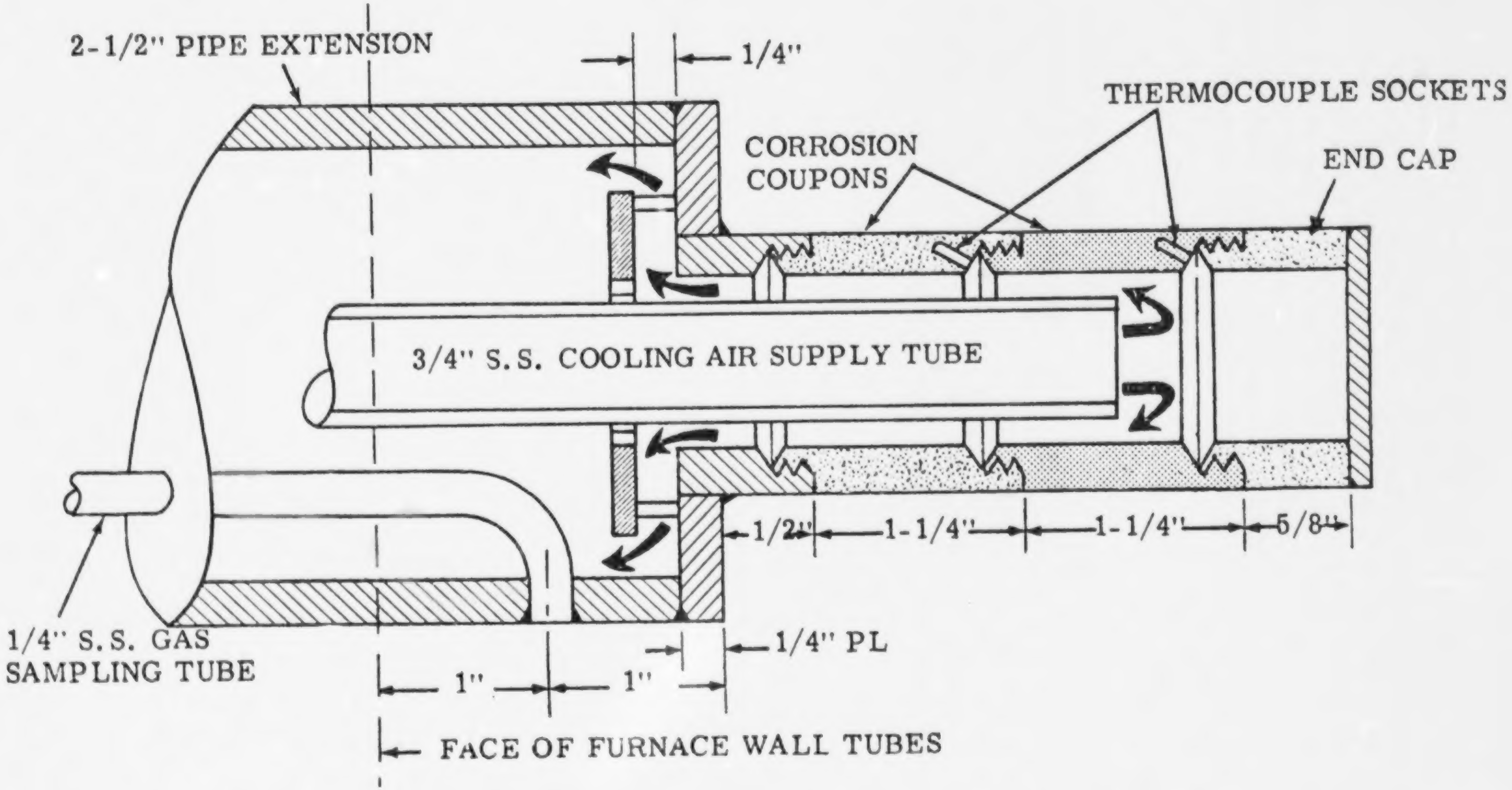
2-1/2" PIPE EXTENSION
1/4"
THERMOCOUPLE SOCKETS
CORROSION COUPONS
END CAP
3/4" S.S. COOLING AIR SUPPLY TUBE
1/2"
1-1/4"
1-1/4"
5/8"
1/4" S.S. GAS SAMPLING TUBE
1/4" PL
1"
1"
FACE OF FURNACE WALL TUBES

Figure 2-3. Corrosion probe, detail of corrosion coupon assembly (inside of furnace).

2.7 SO_2/SO_3 GASEOUS SAMPLING

Wet chemical analyses for the determination of sulfur dioxide and sulfur trioxide content of boiler flue gases were made using an Exxon Research and Engineering Company modification of EPA Method No. 6. Flue gas samples were extracted from the boiler ducts through a heated probe and passed through a series of two adsorbers, the first one containing isopropanol to absorb the sulfur trioxide and the second one a hydrogen peroxide solution in isopropanol to absorb the sulfur dioxide. The amounts absorbed were determined titrimetrically using barium perchlorate as the titrant and thorin as the indicator. Results are presented and discussed in section 3.5.

2.8 STACK PLUME OPACITY

EPA Method 9 procedures were used to take readings of stack plume opacity. The readings were made by two field study team members who had been certified by a U.S. Environmental Protection Agency approved smoke school. Stack plume observations following prescribed procedures were made and recorded for each individual boiler test. Stack plume opacity readings are listed in the tables in Appendix C of this report summarizing the major operating variables and flue gas measurements for each boiler for each test run.

3. RESULTS AND DISCUSSION

The field test results obtained on the individual boilers investigated under a variety of operating conditions in this study are presented in four parts. These parts are, respectively, gaseous emission measurements, flue gas particulate mass loadings and size distributions measured upstream of particulate collector equipment, corrosion probing data obtained in accelerated external furnace tube corrosion tests, and boiler efficiency calculated by the heat loss method. Gaseous emission data and most of the particulate emission data were obtained under normal, as well as modified firing operation. As discussed before, particulate loadings of the flue gas were determined only under conditions corresponding to baseline and low NO_x operation, for purposes of comparison of the relative effect of modified combustion operation on flue gas particulate mass loadings and size distribution in coal combustion. Similarly, the sustained 300-hour corrosion probing tests were conducted to determine relative differences in corrosion rates under baseline and modified combustion modes. It was recognized that short term corrosion probing tests cannot substitute for long term tests in which actual furnace tube wastage is determined. Thus, the measurements in the current studies were made to detect major differences with the anticipation that confirmation of these findings will have to be based on more extensive long term corrosion tests.

The gaseous emission data obtained under baseline and modified firing conditions at various load levels are presented first. Throughout this report, NO_x concentrations are expressed as ppm, adjusted to three percent O_2 in the flue gas, on a dry basis.

In addition to the results obtained in testing coal-fired boilers, this section also presents the gaseous emission data on two mixed fuel (coal-gas and coal-oil) fired units, and an oil-fired gas turbine used for power generation. The mixed fuel tests were run to determine whether NO_x emissions and their response to combustion modifications vary linearly with fuel composition. The gas turbine test, as discussed earlier, was run to broaden the available data base on emissions from power generation combustion equipment.

3.1 GASEOUS EMISSION RESULTS

Test programs were conducted on seven coal-fired boilers consisting of a rear-wall fired, a front-wall fired, an opposed-wall fired and four tangentially fired boilers. Two of the tangentially fired boilers were equipped to fire mixed fuels, one firing mixtures of coal and gas, and the other one firing coal and oil mixtures. Typical cross-sectional diagrams for these types of boilers are shown in Appendix A. Table 2-1 lists each boiler by station and number, boiler manufacturer, type of firing, fuels burned, full load MWe rating, and number of burners. In addition, the number of operating test variables included in each test program and the number of test runs completed are also shown in Table 2-1.

In presenting the results and discussion on the field tests for each of these power generation combustion equipment types, the unit will be briefly described. First, the reasons for its selection will be discussed; second, the key operating variables tested (load, excess air level, staged firing patterns, etc.) will be summarized and the resulting NO_x and other emission data will be given for each test run according to the experimental test design used; and third, these results will be presented in graphical form. Major conclusions and overall findings of this program will be presented in Section 4 of this report. Summary tables containing operating and emission data from each test run for each boiler tested are presented in Appendix C. A separate data supplement report will be available for those interested in detailed raw data.

3.1.1 Widows Creek, Boiler No. 5 (Tennessee Valley Authority)

Tennessee Valley Authority's Unit No. 5 at the Widows Creek Station was the first coal-fired unit tested in our current field test program. The principal reason for including this boiler in the field test program was to obtain short-term (300 hour) corrosion rate data using our corrosion probes to be correlated with long-term (six month) corrosion rate data based both on tube wall thickness measurements and corrosion probe coupon weight loss measurements to be obtained by TVA independently. TVA was provided with details of the ER&E methods used for corrosion probing measurements in order to have a common methodology available for both programs. In addition, this cooperative test program provided TVA personnel with the opportunity to compare the results obtained with their new gaseous and particulate sampling system which was designed based on the features of the ER&E sampling-analytical van.

Widows Creek Unit No. 5 is a 125 MWe, 16-burner, rear-wall, pulverized coal-fired Babcock and Wilcox boiler. Although the boiler originally had a rated generating capacity of 140 MWe, full load is currently considered to be 125 MWe. It has a single, dry-bottom furnace with a division wall. The 16 burners are arranged with four burners in each of four rows. Each row is fed with coal from a separate pulverizer, designated as "A" mill for the top row, through "D" mill supplying coal to the bottom row of burners. The burners are numbered 1 through 4 on each row from left to right when facing the rear wall (see Figure 3-1).

Table C-1 of Appendix C contains a summary of the key operating and emission data from the 31 short-period test runs conducted on this boiler. Table 3-1 presents these results according to the test program experimental design. The four operating variables included in the test program were gross load (125 and 100 MWe), excess air level (normal and low), secondary air register setting (60% and 20% open), and burner firing pattern (S_1 through S_9). The emission data presented in Table 3-1 are average percent O_2 and ppm NO_x (3% O_2, dry basis). Four probes, each containing short, medium, and long sampling tubes were positioned at the centers of 12 equal areas in the flue gas ducts upstream of the air preheaters and downstream of the primary superheater. Composite gas samples from each probe were analyzed sequentially over four complete cycles, resulting in 16 measurements of each gaseous component corresponding to each test run.

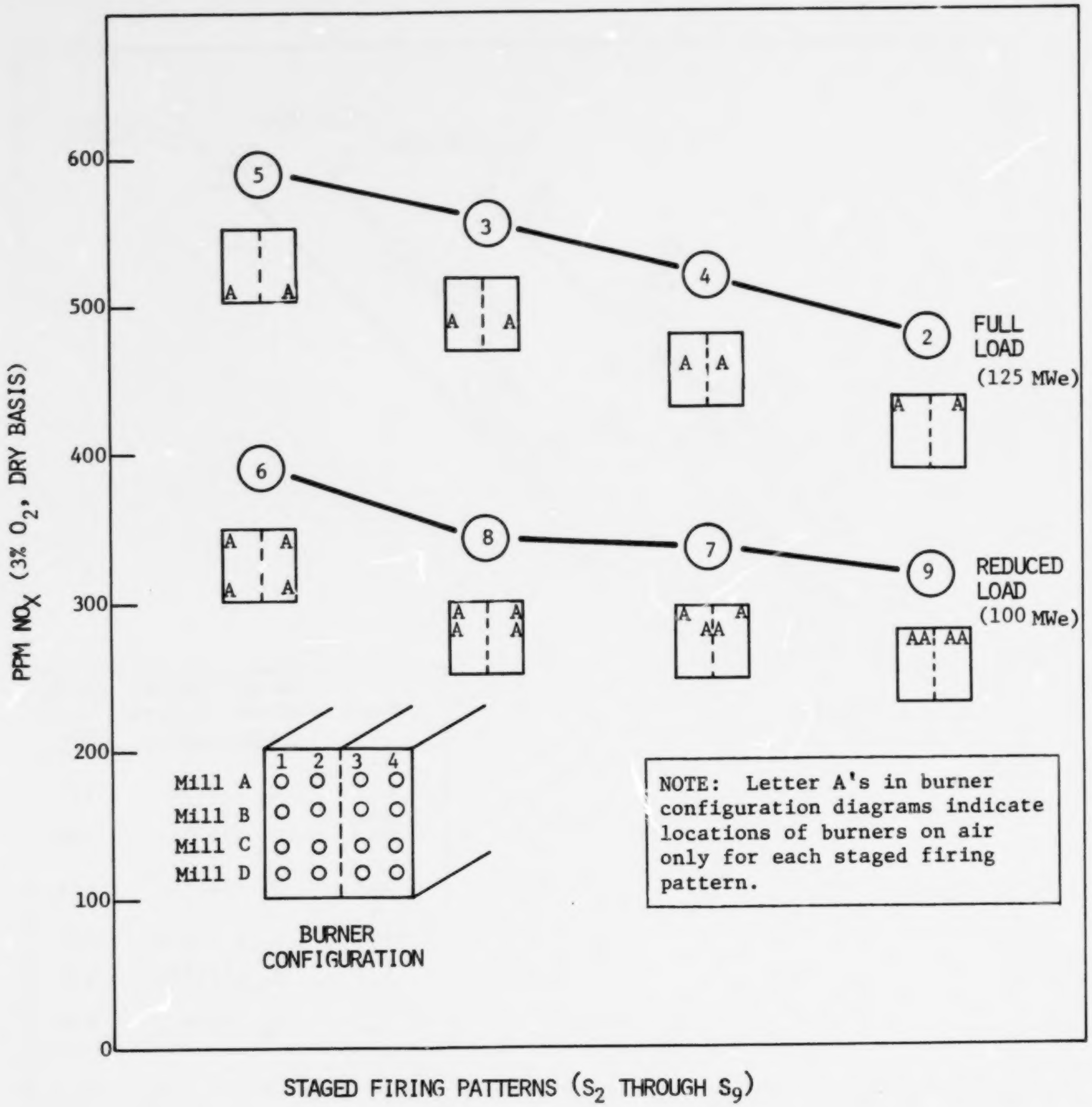

Figure 3-1. NO_x emissions vs. staged firing patterns for Widows Creek No. 5 unit.

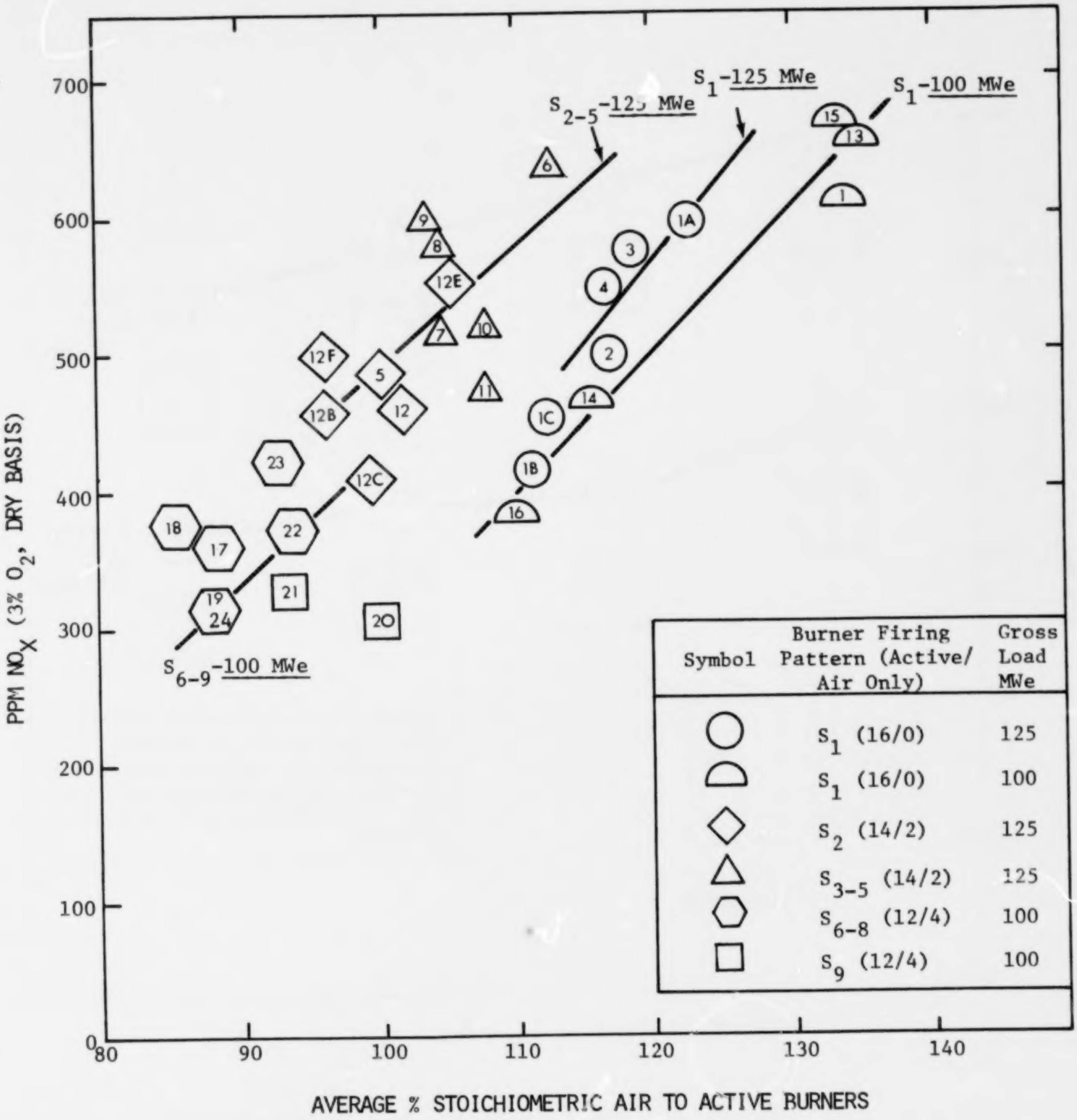

Figure 3-2. PPM NO$_x$ vs. % stoichiometric air to active burners for Widows Creek, boiler no. 5.

TABLE 3-1

TEST PROGRAM EXPERIMENTAL DESIGN - WIDOWS CREEK NO. 5

(RUN NO., AVERAGE % O_2 AND AVERAGE PPM NO_x EMISSIONS (3% O_2, DRY))

Secondary Air	L_1-Full Load (125 MW)				L_2-Reduced Load (100 MW)			
	A_1-Normal		A_2-Low Air		A_1-Normal Air		A_2-Low Air	
Firing Pattern	60% Open	20% Open	60% Open	20% Open	60% Open	20% Open	60% Open	20% Open
S_1-16 Firing Coal	(1A) 4.0%-597 (1B) 2.4%-409 (1C) 2.5%-441	③ 3.5% 574	② 3.2% 502	④ 3.2% 548	⑬ 5.5%-660 ⑭ 5.4%-603	⑮ 5.4% 667	⑭ 3.0% 462	⑯ 2.1% 381
S_2-14 Firing Coal (A_1A_4 Air Only)			⑤ 3.0% 486	⑫ 3.2% 468				
S_3-14 Firing Coal (C_1C_4 Air Only)			⑥ 4.8% 639	⑪ 4.1% 474				
S_4-14 Firing Coal (B_1B_4 Air Only)			⑩ 4.0% 521	⑦ 3.6% 517				
S_5-14 Firing Coal (D_1D_4 Air Only)			⑨ 3.4% 598	⑧ 3.6% 580				
S_6-12 Firing Coal ($A_1A_4D_1D_4$ Air Only)							⑰ 3.2% 365	㉓ 4.3% 421
S_7-12 Firing Coal ($A_1A_4B_2B_3$ Air Only)							⑱ 3.0% 374	㉔ 3.3% 302
S_8-12 Firing Coal ($A_1A_4B_1B_4$ Air Only)							㉒ 4.4% 368	⑲ 3.3% 316
S_9-12 Firing Coal ($A_1A_2A_3A_4$ Air Only)							㉑ 4.5% 329	⑳ 5.3% 305

Figure 3-2 presents the NO_x emissions measured, plotted as the function of the average percent stoichiometric air to active burners. Least squares lines have been fitted to the data points for normal firing at 125 MWe, normal firing at 100 MWe and staged firing at 125 MWe. Test run numbers are shown within the symbols which represent different operating conditions. The test runs made with the firing patterns that produced the lowest NO_x emission levels with two burners on air only, and four burners on air only, were S_2 and S_9, respectively. These patterns are indicated by diamonds and squares, respectively, in Figure 3-2.

Baseline NO_x emissions calculated from the least squares regression lines for 120% stoichiometric air were 332 and 296 ng/J (567 ppm and 506 ppm) at 125 and 100 MWe, respectively. These results are about 58 ng/J (100 ppm) lower than the results obtained in our previous field test program on Widows Creek "sister" Boiler No. 6 (2). This difference is probably due to the differences in the coals fired and the fact that the inside walls of No. 5 furnace were much cleaner (less ash deposit) than the furnace walls of No. 6 boiler when it was previously tested.

Operation with low excess air firing reduced NO_x emissions as shown by the least squares line of Figure 3-2. A reduction of 10% in the stoichiometric air supplied to the burners (i.e., 120% to 110%) reduced NO_x emissions by 21% both at full load, from 332 ng/J to 261 ng/J (from 567 to 447 ppm) and at 100 MWe load, from 288 to 227 ng/J (from 493 to 388 ppm) with normal, 16 burner firing operation.

Decreasing the gross load by 20% from 125 MWe to 100 MWe with normal excess air, 16 burner firing would result in an estimated lowering of NO_x emissions by 13%, from 332 ng/J (567 ppm) to 288 ng/J (493 ppm) at 120% stoichiometric air. Since the actual excess air level was increased during reduced load operation, actual NO_x emissions were higher during reduced load, "normal" air operation than under normal air, full load operation.

Staged firing test runs were conducted only at low excess air levels. This procedure was used so that additional staged firing patterns could be tested within the same test period, and to concentrate the effect on measurements at low excess air operation. The minimum level of excess air was established based on what was considered acceptable CO emissions [less than 117 ng/J (200 ppm)] and on normal stack plume opacity.

Four staged firing patterns were tested at 125 MWe load with two burners on air only (14 active burners). The lowest average NO_x emissions were measured with the top row outer burners on air only (477 ppm using S_2). The next lowest average NO_x emissions were measured with next to top row wing burners on air only at 304 ng/J (519 ppm) using S_4 while S_3 and S_5 staged firing patterns with the next to bottom and the bottom row wing burners on air only produced an average of 325 and 344 ng/J (557 and 589 ppm) NO_x emissions, respectively. Thus, there was a consistent pattern of decreasing NO_x emissions as the "air only" burners were shifted from "underfire" air through the bottom row to "overfire" air through the top row of burners, as shown by the top line of Figure 3-1. Changing the secondary air register settings from 60% open to 20% open on the active burners consistently resulted in lowered NO_x emissions for all four firing patterns, with an average reduction in NO_x of 9%. The best operating combination of burner register setting and staged firing pattern (test run No. 12) produced an average NO_x emission level of 274 ng/J (468 ppm) which was 22% lower than the 349 ng/J (597 ppm) under actual base level operation (test run No. 1A).

Four staged firing patterns were also tested at 100 MWe load with four burners on air only (12 active burners). The lowest average NO_x emission level of 185 ng/J (317 ppm), was measured with the top row of burners fed from A mill on air only (S_9). The next to lowest NO_x level of 198 ng/J (338 ppm) was measured when operating with A_1, B_2, B_3, and A_4 burners on air only (S_7). Staged firing pattern S_8 (A_1, A_4, B_1 and B_4 burners on air only) produced NO_x emissions slightly higher than firing pattern S_7, while firing pattern S_6 (A_1, A_4, D_1 and D_4 burners on air only) produced the highest average NO_x emission level of 230 ng/J (393 ppm) among the 4 staged burner firing patterns. Reducing secondary air register settings from the 60% open to the 20% open position on active burners reduced NO_x emissions by an average of 6% for these four firing patterns. The combination of staged firing pattern (S_9) and air register setting (test run No. 20) produced the lowest NO_x emission level of 178 ng/J (305 ppm), or about 49% below the level for full load, baseline operation. The average NO_x emission levels measured for staged firing patterns 6 through 9 are plotted in Figure 3-1, where the data points are connected by the lower solid line.

Two factors appear to be responsible for lower NO_x emissions when operating with secondary air register settings of 20% open on the active burners. The first factor is that the overall level of excess air can be lowered (without exceeding the maximum acceptable CO emission levels), and the second one is that operating in this manner allows lower substoichiometric air to be supplied to the active burners.

The test results obtained from Widows Creek boiler No. 5 were in agreement with expectations based on the results obtained on the previously tested No. 6 boiler and other front-wall, coal-fired boilers tested in previous studies (1,2). Each of the 4 operating variables, load, excess air level, secondary air register setting and firing pattern has a significant effect on NO_x emission levels. From a full load, base level NO_x emission level of 332 ng/J (567 ppm) at 120% stoichiometric air, low excess air operation reduced NO_x emissions by about 12% to 294 ng/J (502 ppm). Reducing load by 20% to 100 MWe reduced NO_x emissions by 13%. Low excess air, staged firing at full load reduced NO_x emissions to as [illegible] as 274 ng/J (468 ppm) when secondary air registers were closed down to "20% open" setting. Low excess air, staged firing at reduced load (100 MWe) reduced NO_x emissions to as low as 178 ng/J (305 ppm) with the burners supplied by A mill on air only and with closed down secondary air registers. The most effective staged firing patterns are those that maximize the amount of "overfire" air across the burner area.

3.1.2 Ernest C. Gaston, Boiler No. 1 (Southern Electric Generating Company)

Southern Electric Generating Company's Boiler No. 1 at the Ernest C. Gaston Station, was the second boiler tested in our current field test program. The major reason for selecting this boiler was that it had been retro-fitted with newly designed, low NO_x burners by its manufacturer, Babcock and Wilcox. These dual register compartmentalized wind box burners produce a limited turbulence, controlled diffusion flame. They are designed to minimize the amount of fuel and air mixed at the burner to that required to obtain ignition and to sustain combustion of the fuel. Figure 3-3 presents a line diagram of the dual register pulverized coal burners installed in Boiler No. 1.

Gaston Units No. 1 and 2 are 270 MWe, 18-burner, horizontally opposed, pulverized coal fired Babcock and Wilcox boilers. Two division walls divide each furnace into 3 equal compartments, each having six burners arranged 3 high in both the front and rear walls of the furnace. The furnace is 18.3 m (60 feet) wide, with a volume of 3950 m^3 (139,500 cubic feet) and a total wall area of 2391 m^2 (25,732 square feet). Six pulverizers each with 16,300 kg (36,000 pounds) capacity feed coal to 3 burners each as shown in Figure 3-4. The maximum continuous rating of each boiler is 771,000 kg (1,700,000 pounds) of steam per hour. Steam design pressure at superheat outlet is 303 kPa (2,075 PSIG) at 811 K (1000°F). Steam design pressure at reheater outlet is 72 kPa (495 PSIG) at 811 K (1000°F). Steam temperature controls include flue gas recirculation into the hopper area of the furnace and spray attemperators for primary superheat and reheat.

Table 2 of Appendix C contains a summary of the key operating and emissions data collected on this boiler. Table 3-2 presents these results according to the test program experimental design. The five operating variables (and experimental levels tested) included in the test program were:

1. Gross load [full load (270 MWe), 250 MWe, and 190 MWe to 205 MWe].
2. Excess air level (high, normal and low).
3. Secondary air register setting (30, 50, 70, and 100% open).
4. Tertiary air register setting (50 and 100% open).
5. Firing pattern (all burners firing, 1 top mill off, 2 top mills off).

The emission data shown in Table 3-2 and Table 2 of Appendix C are average % oxygen and ppm NO_x (3% O_2, dry basis). Four probes, each containing short, medium and long sampling tubes were positioned near the centers of 12 equal areas in the flue gas ducts between the economizer and the air preheaters.

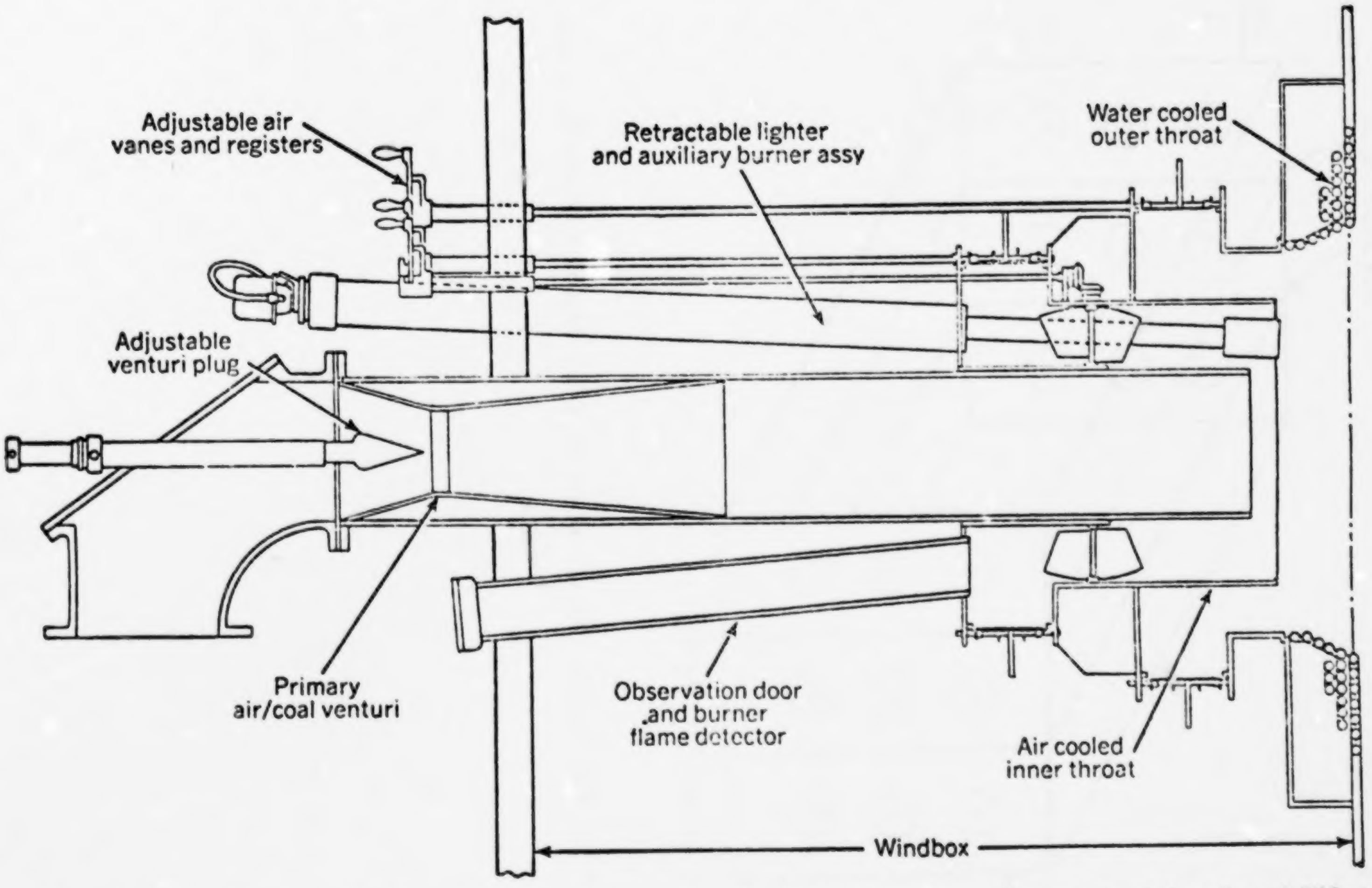
Adjustable air
vanes and registers
Retractable lighter
and auxiliary burner assy
Water cooled
outer throat
Adjustable
venturi plug
Primary
air/coal venturi
Observation door
and burner
flame detector
Air cooled
inner throat
Windbox

Figure 3-3. Babcock and Wilcox dual register pulverized coal burner. (Courtesy, Babcock and Wilcox Company)

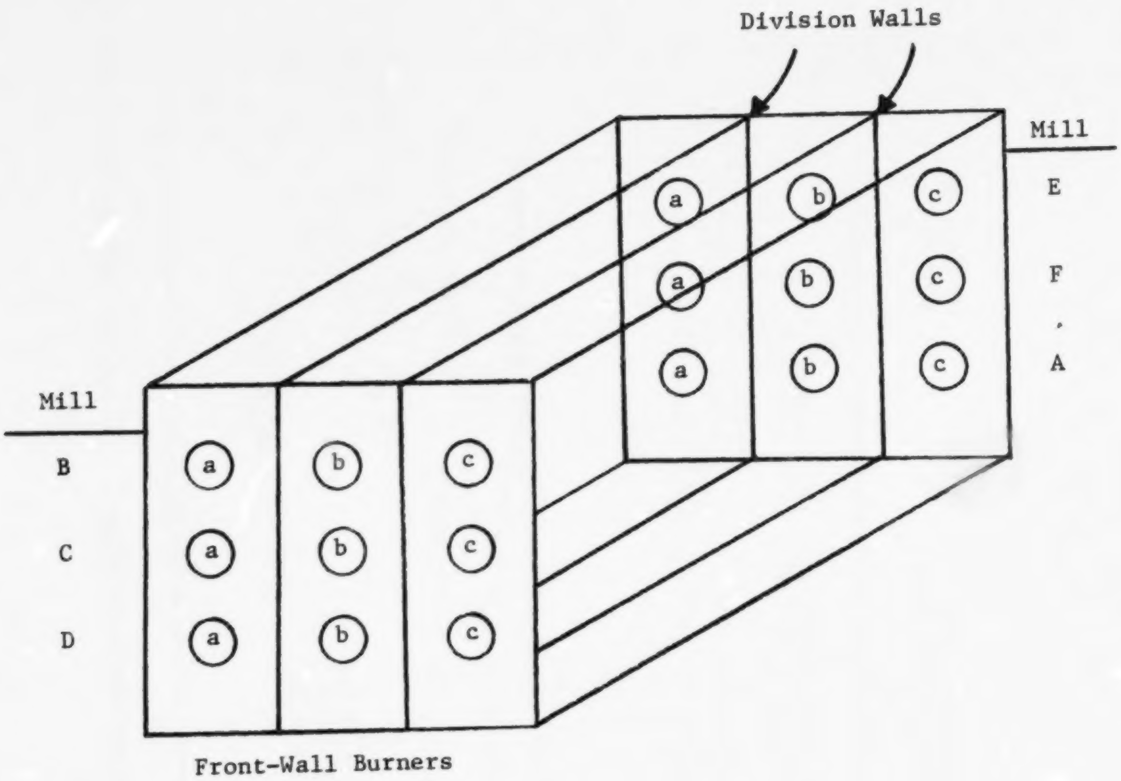
Division Walls
Mill
E
F
A
Mill
B
C
D
a
b
c
Front-Wall Burners

Figure 3-4. Mill-burner configuration of E. C. Gaston boilers No. 1 and 2

TABLE 3-2

TEST PROGRAM EXPERIMENTAL DESIGN - ERNEST C. GASTON BOILER NO. 1

(RUN NO., AVERAGE % O_2 AND AVERAGE ppm NO_x - 3% O_2, DRY BASIS)

		L1 (268 - 273 MWe)				L2 (236 - 250 MWe)		L3 (187 - 208 MWe)					L4 (148 MWe)
		A_2-Normal Excess Air		A_3-Low Excess Air		A_2-Nor. Air	A_3-Low Air	A_1-Maximum Excess Air		A_2-Normal Excess Air		A_3-Low Air	A_2-Nor. Air
Firing Pattern	Tert. Air / Secon. Air	SA_1 - 30-50%	SA_2 - 70-100%	SA_2 - 30-50%	SA_2 - 70-100%	SA_2 - 70%	SA_2 - 70%	SA_1 - 30%	SA_2 - 70%	SA_1 - 30%	SA_2 - 70%	SA_2 - 70%	SA_2 - 70%
S_1 - All Burners Firing Coal	T_1 - 100% Open	㉑ 3.7% 377 ㉒ 3.6% 409	① 4.3%-389 ㉓ 3.9 -356 ㉔ 3.7 -349 ㉕ 3.8 -390 ㉖ 3.9 -349 ㉗ 3.9 -316 ㉟ 4.4%-372	③ 2.4% 289 ④ 2.6% 329 ⑥ 2.3% 318	② 2.4% 278 ⑤ 2.4% 336	㊲ 3.9% 322		⑲ 6.8% 451	⑱ 7.0% 454	⑳ 3.9% 297	⑰ 4.9% 325		
	T_3 - 50% Open			⑦ 2.5% 362 ⑧ 2.2% 312	⑨ 2% 296								
S_2 - B or E Mill On Air Only	T_1 - 100% Open					⑪ 3.6% 289	⑫ 2.6% 257 ⑯ 1.9% 240				㊱ 3.8% 301		
S_3 - B and E Mills On Air Only	T_1 - 100% Open										⑬ 3.6% 240	⑭ 1.6% 182	㉞ 6.9% 148
	T_2 - 70% Open											⑮ 1.8% 200	

Composite gas samples from each probe were analyzed and recorded in turn over four complete cycles, resulting in 16 measurements of each gaseous component in each test run. The level of excess air on "low" excess air test runs was established as the minimum excess air level operation that would not produce over 115 ng/J (200 ppm) CO emissions.

Figure 3-5 is a plot of ppm NO_x (3% O_2, dry basis) vs. average % stoichiometric air to active burners. The numbers within the plotted symbols identify the run number from which the data were obtained. Least squares, linear regression lines were calculated from the data points representing normal firing (S_1) at 270 MWe, normal firing at 205 MWe, staged firing (S_2 - top mill burners on air only on front or rear wall) at 250 MWe and staged firing operation (S_3 - top mill burners of front and rear wall on air only) at 190 MWe.

Baseline NO_x emissions calculated from the least squares regression lines shown in Figure 3-5 for 120% stoichiometric air were 204 and 160 ng/J (356 ppm and 279 ppm) at 270 and 205 MWe, respectively on Boiler No. 1 using the new low NO_x burners. Thus, a load reduction of 24% resulted in a 22% reduction in NO_x emissions. From a full load, base level NO_x emission level of 220 ng/J (377 ppm) [124% stoichiometric air], low excess air operating reduced NO_x emissions by about 20% to 178 ng/J (305 ppm). Two staged firing patterns were tested: B or E mill burners on air only (S_2) and E and B mill burners on air only (S_3). Low excess air, staged firing at 250 MWe reduced NO_x emissions to as low as 140 ng/J (240 ppm) with B mill burners on air only (S_2). Low excess air, staged firing at a lower loads of 190 and 148 MWe reduced NO_x emissions to as low as 106 and 87 ng/J (182 and 148 ppm), respectively, with both E and B mill burners on air only (S_3). Analysis of secondary air register setting vs. NO_x shows that the lowest NO_x level was generally reached when the register setting was approximately 70% open with lower and higher settings producing higher NO_x levels.

NO_x measurements on Boiler No. 2 when operated at full load of 270 MWe, averaged 346 ng/J (591 ppm) at 24% excess air. Boiler No. 1 when operated at full load of 270 MWe, averaged 220 ng/J (377 ppm) at 24% excess air. Therefore, the new dual register burners used in Boiler No. 1 reduced NO_x emissions significantly, i.e., by 36% compared to conventional Babcock and Wilcox burners.

A short-term program of experimental runs was conducted to determine the effect of reduced pulverizer air temperature on NO_x emissions. At the normal operating temperature of 350 K (170°F), average NO_x emission measured 211 ng/J (361 ppm), while at a reduced temperature of 333 K (140°F), average NO_x emissions measured 183 ng/J (313 ppm). Thus, a 12% reduction in NO_x emissions resulted from the use of lowered pulverizer air temperature. Further experimentation would be necessary to determine if the reduced temperature operation would result in mill operating problems and to validate these results over a longer time period with different coals and pulverizer settings.

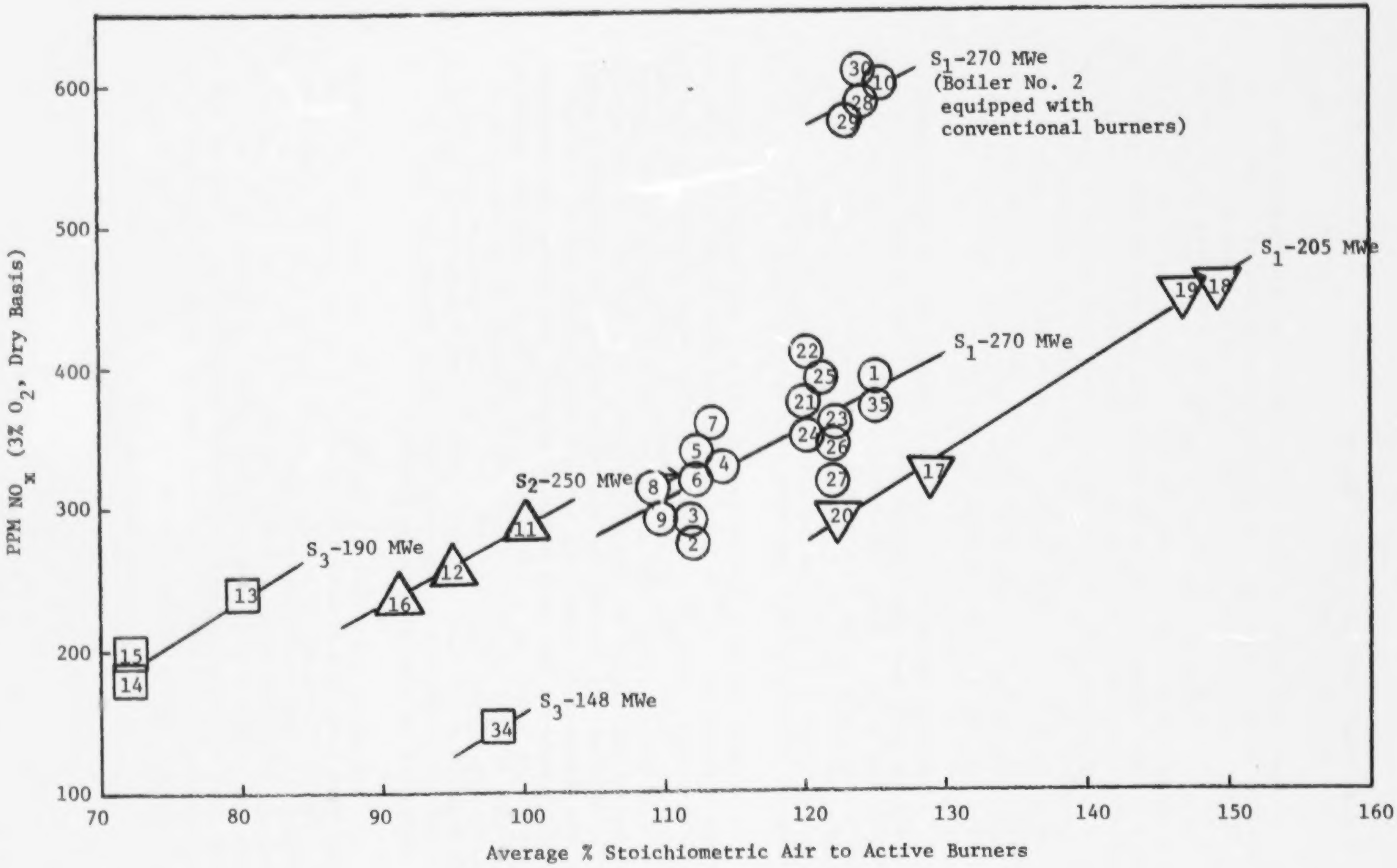

Figure 3-5. NO$_x$ emissions vs. % stoichiometric air for Gaston boiler No. 1.

3.1.3 Navajo Station, Boiler No. 2 Salt River Project

Navajo Unit No. 2 is a twin furnace, 800 MWe, Combustion Engineering Boiler. The two-cell furnace has a volume of 13,182 m^3 (465,500 cu. ft.), width of 25.5 m (83 ft. 6-3/4 in.) and front to rear length of 12.45 m (40 ft. 10-1/4 in.). Maximum continuous rated primary steam flow is 2,450,000 kg/hr. (5,400,000 lb./hr.), at 814 K (1005°F), with a reheat steam flow of 2,200,000 kg/hr. (4,850,000 lb./hr.) at 813 K (1003°F). The normal fuel fired is Black Mesa sub-bituminous coal with a higher heating value of 24950 kJ/kg (10,725 BTU/lb.), and containing 10.4% ash, 10.3% moisture, 38% volatile material and 41.4% carbon. At maximum continuous rating, 296,000 kg/hr. (652,000 lb./hr.) of coal are fired and the design furnace efficiency is 88.77%. Seven pulverizers feed 56 burners arranged to fire at seven different levels. Overfire tilting air ports are located above the top row of burners. Main steam pressure is 523 kPa (3590 lbs./sq. in.) at the superheater outlet.

Table 3, Appendix C, contains a summary of the major operating variables and flue gas measurements for each of the 36 test runs completed on Navajo No. 2 Unit. Operating variables included in the experimental program were gross load, excess air level, burner tilt, and firing pattern. Table 3-3 presents a summary of emission data (run no., % O_2, ppm NO_x) arranged according to the planned experimental design. Figures 3-6 through 3-9 display the test data in graphical form.

Figure 3-6 is a plot of ppm NO_x (3% O_2, dry basis) vs. average % oxygen measured in the flue gas for all test runs conducted at full load with normal firing (S_1). Lines have been drawn to show the effect of excess air level on NO_x emission levels for +25°, +10 to +15°, 0° and -10 to -15° burner tilts. The effect of overfire cooling air (about 10% open) has no beneficial NO_x reduction effect when the burners are tilted up 25°. However, as the burners are tilted towards the horizontal position, the distance of separation between the overfire cooling air and the bulk flame zone increases and increased NO_x reductions are apparent. Operating with burner tilted at -10 to -15° produced higher NO_x emission levels than 0° tilt operation due to the concentration of heat release in the bottom of the furnace. The least squares regression line calculated from the seven test runs made at +10 to +15° burner tilt (ppm NO_x = 118 + 51% O_2), showed an average reduction of 51 ppm NO_x for each percent reduction in flue gas oxygen content.

Figure 3-7 is a plot of ppm NO_x (3% O_2, dry basis) vs. % oxygen for the test runs made at full load with overfire air dampers 100% open (S_7). The least squares regression line calculated from the eight test runs conducted with +10 to +15° burner tilt (ppm NO_x = 90 + 54% O_2) showed an average reduction of 32 ng/J (54 ppm) NO_x for each per cent reduction in flue gas oxygen content. The average ppm NO_x emission level for the five S_7 test runs conducted at the lowest excess air level (3.5 to 3.8% O_2) was 165 ng/J (282 ppm) or 17% below the 199 ng/J (341 ppm) NO_x level for comparable excess air S_1 test runs.

TABLE 3-3

TEST PROGRAM EXPERIMENTAL DESIGN - RUN NO., % O_2, PPM NO_x

(NAVAJO NO. 2 UNIT - FULL LOAD (795-808 (MWe)

	Burner Tilt / Firing Pattern	S_1-Normal Firing	S_2-Top Row Air Only	S_4-* 25% OFA	S_5-* 50% OFA	S_6-* 75% OFA	S_7-* 100% OFA
A_1- Normal Excess Air	T_1 -10° to -15°	(2A) 3.9% 332					⑲ 5.2% 346
	T_2 Horiz.	① 4.9% 343					㉑ 5.4% 329
	T_3 +10° to +15°	(3B) 5.4% 416 (3C) 5.4% 385 ③ 4.9% 366 (3D) 4.8% 346 (7A) 5.2% 378 (7B) 5.2% 383	⑦ 5.0% 318	⑪ 4.0% 332	⑬ 3.9% 310	⑮ 3.8% 292	(17A) 5.2% 354 (18B) 4.4% 349 (18C) 4.6% 346 (18D) 4.6% 349
	T_4 +25°	(3A) 4.8% 492					
A_2- Low Excess Air	T_1 -15°	⑤ 3.8% 314					⑳ 3.5% 271
	T_2 Horiz.	④ 4.2% 309					㉒ 3.8% 289
	T_3 +10° to 15°	⑥ 4.0% 335 (8A) 3.6% 298	⑧ 3.6% 259	⑫ 3.6% 328	⑭ 3.6% 326	⑯ 4.0% 289	⑱ 3.6% 282 (18A) 4.2% 291 ⑰ 3.6% 288 (18E) 3.7% 280
	T_4 +25°	(6A) 3.8% 411					

* Overfire air registers were set at 25% open for S_4, 50% open for S_5, 75% open for S_6 and 100% open for S_7.

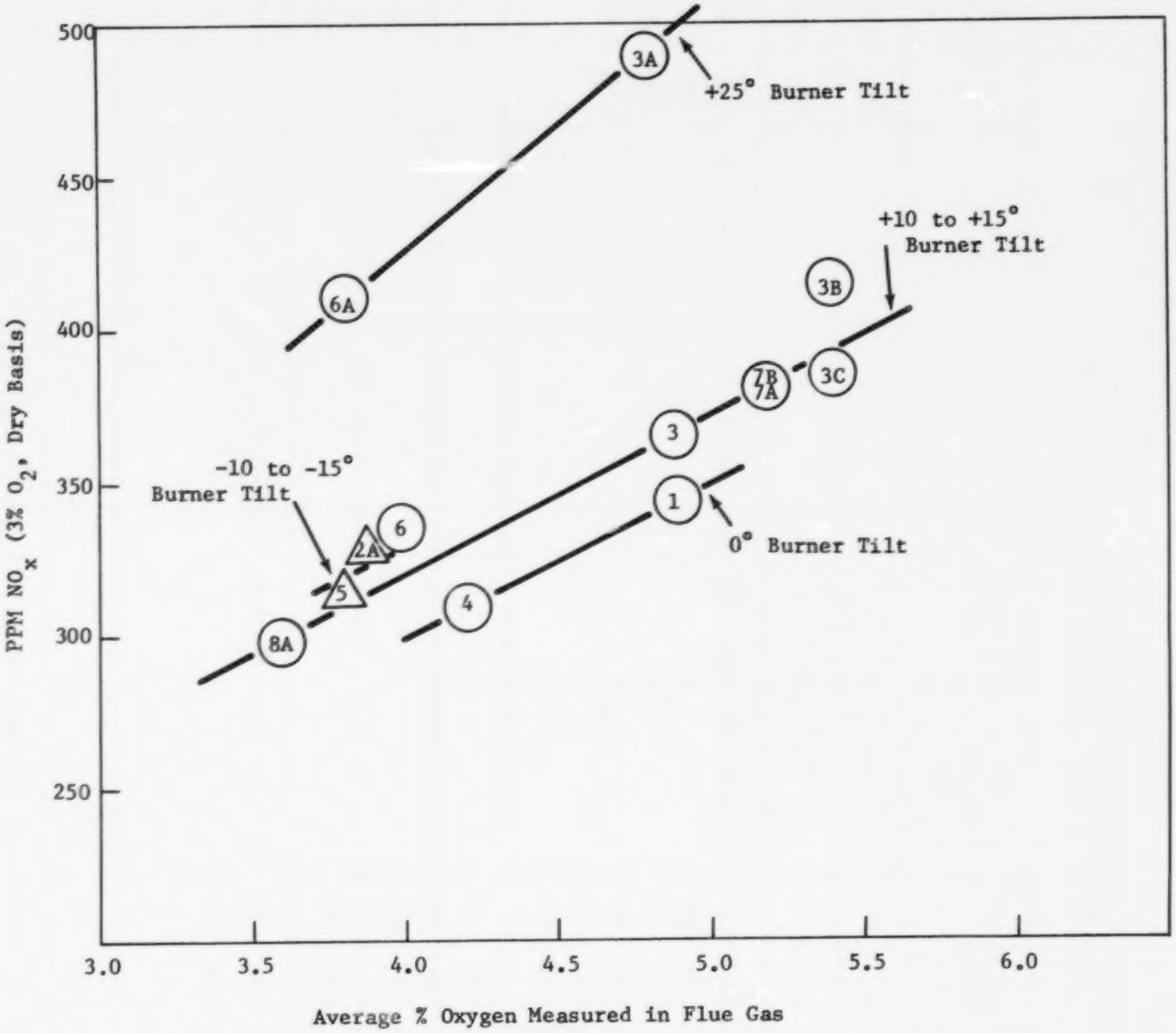

Figure 3-6. PPM NO$_x$ emissions vs. % oxygen for Navajo No. 2 unit under full load, normal firing operation.

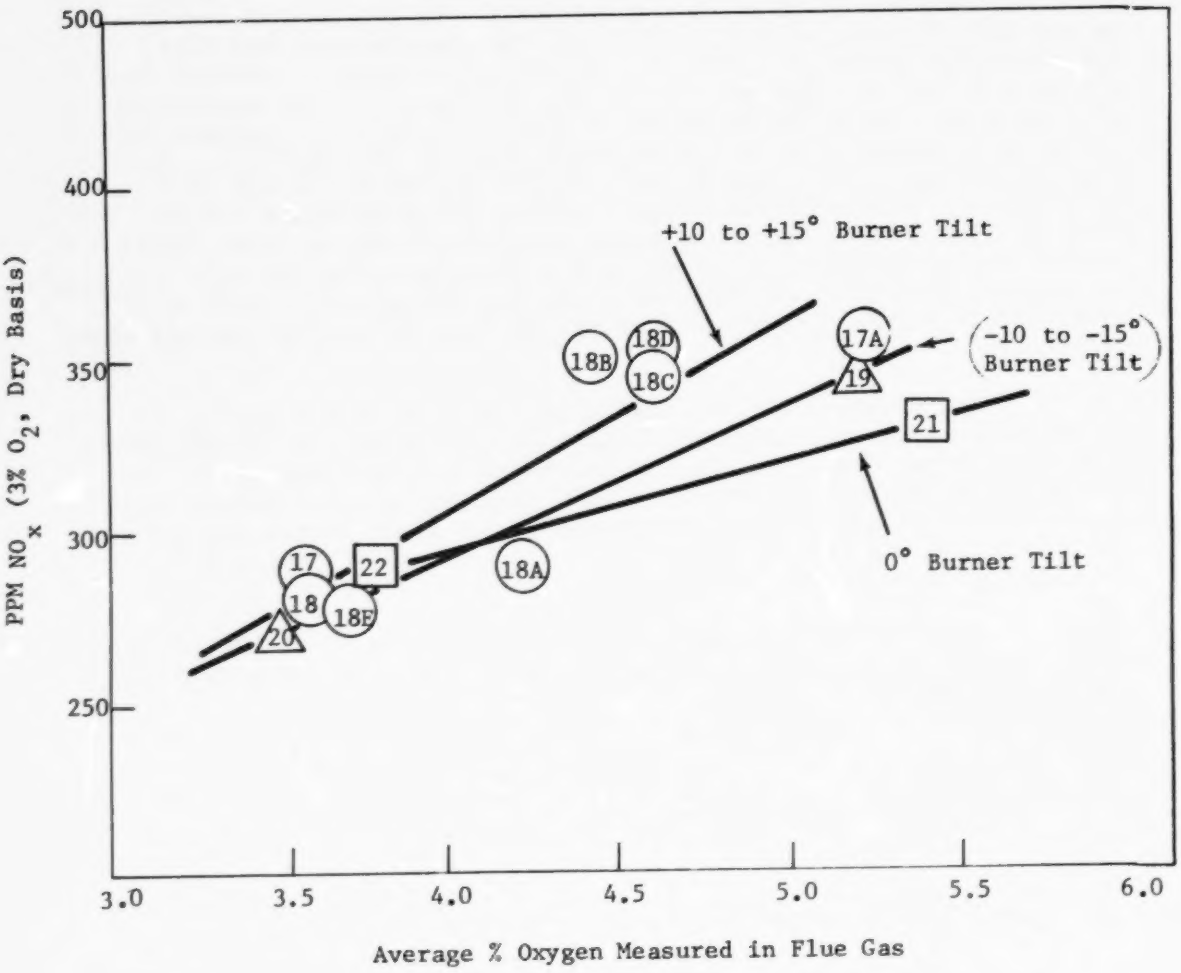

Figure 3-7. PPM NO_x emissions vs. % oxygen for Navajo No. 2 unit operating with overfire air dampers 100% open.

Figure 3-8 is a plot of ppm NO_x vs. % oxygen for the S_2, S_4, S_5 and S_6 staged firing test runs. The least squares line labeled S_7 from Figure 3-7 was drawn on Figure 3-8 for purposes of comparison. Short lines parallel to the S_7 line were drawn through the averaged data for S_4, S_5 and S_6 test runs. The lowest NO_x emissions resulted from test runs No. 7 and No. 8 conducted with the top tier of burners on air only (S_2) and cooling air through the overfire air registers. The beneficial effect of increasing overfire air register openings from 25% (S_4) to 50% (S_5) and then to 75% (S_6) is apparent from examination of Figure 3-8. Furthermore, Figure 3-9 was constructed to present the effect of changing overfire air register settings more directly. Only test runs conducted with approximately equal excess air levels (3.6 to 4.0% O_2) and burner tilts (+10° to +15°) are shown on Figure 3-9 so that the effect of overfire air damper settings on NO_x emission levels can be seen directly. Average NO_x levels decreased from 193 ng/J (330 ppm) to 186 ng/J (318 ppm), 170 ng/J (290 ppm) and 165 ng/J (283 ppm) as the overfire air damper openings were increased from 25% to 50%, 75% and 100%, respectively.

The effect of boiler load on NO_x emission levels can be estimated from the data shown in Table 3-4. The first six columns provide data on the three test runs conducted at reduced loads of 565 to 305 MWe. The seventh and eighth columns list NO_x emission levels measured for full load operation at comparable excess air levels and burner tilts based on the data of Figure 3-6. The last column indicates the % reduction in NO_x levels at the reduced loads.

Thus, a 29% reduction in load resulted in a 10 to 20% reduction in NO_x emission levels and a 52% reduction in load resulted in a 26% NO_x emission reduction.

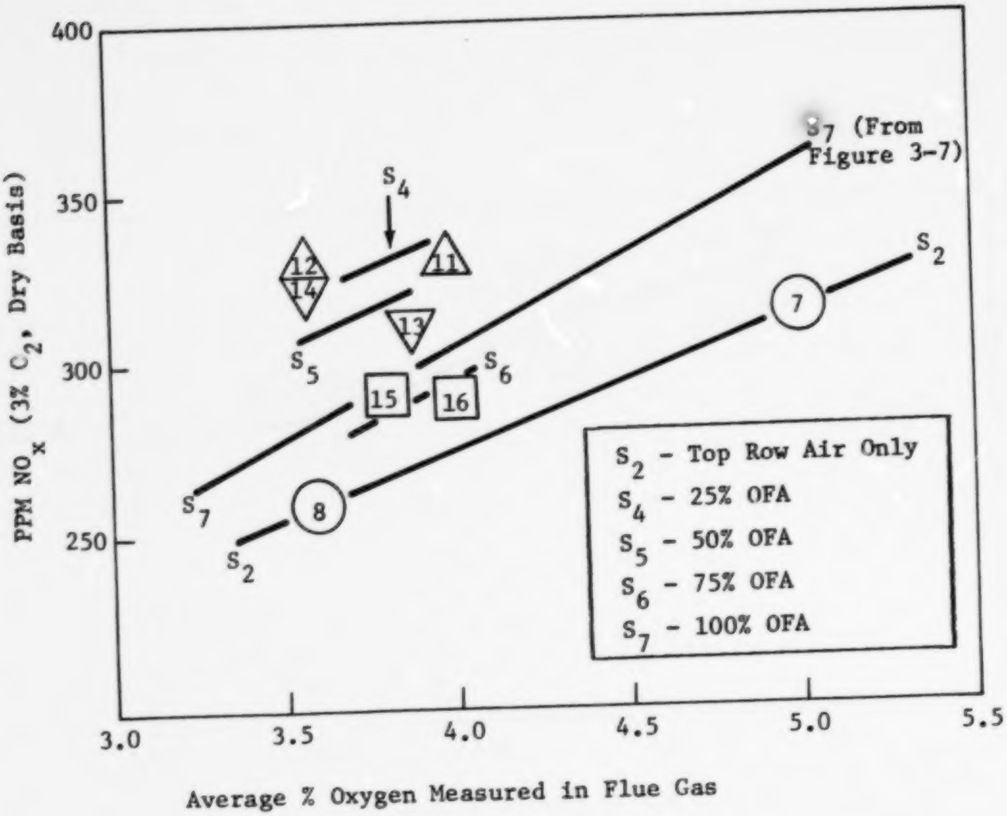

Figure 3-8. PPM NO_x emissions vs. % oxygen for Navajo No. 2 unit under staged firing operation.

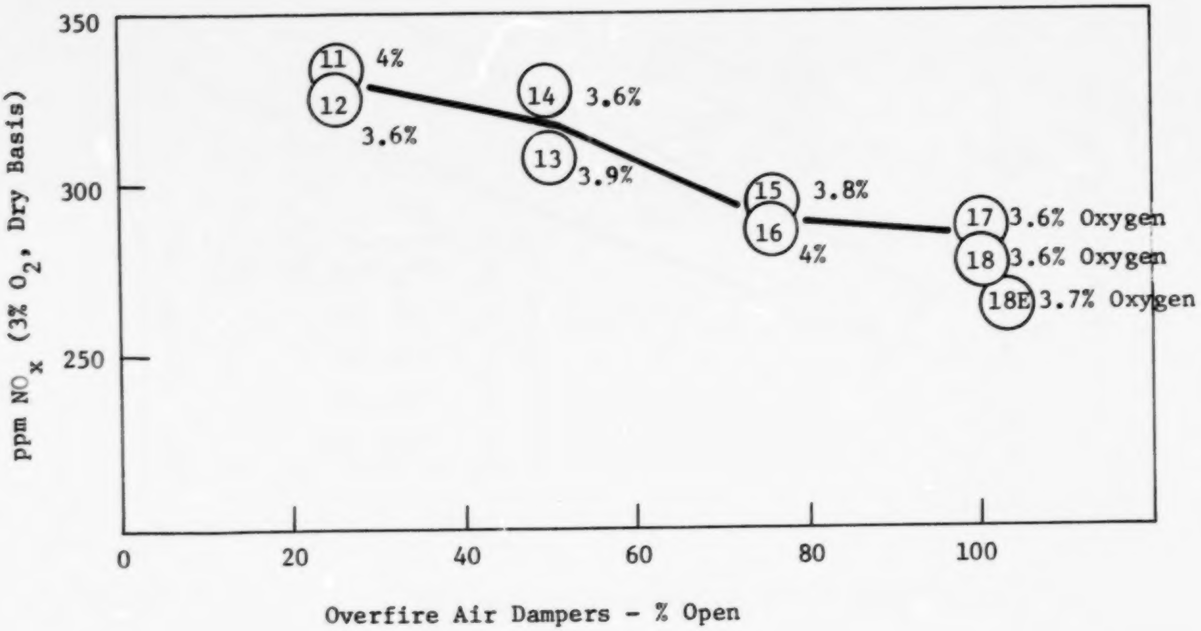

Figure 3-9. Effect of opening overfire air dampers on NO_x emissions from Navajo No. 2 unit at full load.

TABLE 3-4

REDUCED LOAD TEST DATA

(Navajo No. 2 Unit)

Run No.	Gross Load (MWe)	Burner Tilt	% O_2	NO_x Emissions Reduced Load ng/J	ppm	Full Load ng/J	ppm	% NO_x Reduction
23	565	+10°	5.3%	205	350	226	388	10
24	565	+30°	5.0%	236	404	296	506	20
18D	305	+25°	4.6%	204	349	277	474	26

3.1.4 Comanche Station, Boiler No. 1
Public Service Co. of Colorado, Pueblo, Colorado

Comanche Unit No. 1 is a single furnace, tangentially fired, Combustion Engineering boiler. It was selected for this program because it is a new unit equipped with overfire air ports (OFA) over the top level of burners for NO_x emissions control. The furnace has a volume of 6739 m^3 (238,000 cu. ft.), width of 13.8 m (45 ft. 4 in.) and front to rear length of 12.2 m (40 ft.). Maximum continuous rated primary steam flow at 365 kPa (2500 lb./in^2) is 1,149,000 kg/hr. (2,534,000 lb./hr.) at 814 K (1005°F) with a reheat steam flow of 997,500 kg/hr. (2,155,000 lb./hr.) at 814 K (1005°F). A Wyoming sub-bituminous coal is fired with nominal values of 19,190 kJ/kg (8,250 BTU/lb.), 5.2% ash, 0.57% sulfur, 29% moisture, 32.4% fixed carbon and 33.4% volatile matter, and an ash fusion temperature of 1450 K (2150°F). At maximum continuous rating (350 MWe), 194,000 kg/hr. (428,000 lb./hr.) coal is fired and a furnace efficiency of 84.65% is predicted. Five pulverizers feed 20 burners firing at 5 levels (designated "A" for the top and "E" for the bottom levels).

This unit was the first pulverized coal fired boiler designed by Combustion Engineering to have overfire air ports (through extended windboxes) for reducing nitrogen oxides emissions. The boiler is equipped with a hot electrostatic precipitator for particulate collection.

Table 4 of Appendix C contains a summary of the major operating variables and flue gas measurements for each of the 30 test runs completed on Comanche Unit No. 1. Operating variables included in the experimental program were overfire air damper settings (closed to 100% open and horizontal to -15° tilt), burner nozzle tilt (horizontal to -26°), secondary air register settings (22-40% open auxiliary and 100% open coal registers) and boiler load (316 to 340 MWe).

Several operating limitations were experienced due to load, weather and boiler conditions. July and August are peak load demand months and thus only normal load variations were treated. Only normal excess air operation was used due to maximum ID fan capacity (economizer section blockage) and plant operating management's desire to avoid possible slagging problems (previously encountered) that might be caused by low excess air operation. Burners are normally operated tilted at -20^o from the horizontal to avoid high steam outlet temperature and to reduce excess air level variations to a minimum between flue gas economizer outlet ducts. Thus, the burners were not tilted above horizontal. Secondary air register settings at full load are varied automatically to maintain 18 to 20 mPa (4.5 to 5.0 in. H_2O) furnace to windbox differential by varying auxiliary register settings, while the coal air registers are maintained 100% open. Thus, if the overfire air registers are opened from 5% (closed) to 50% open, the auxiliary air registers automatically close to 22 to 26% open from about 50% open. Maximum gross load during our test period was 320 to 340 MWe due to limited ID fan capacity mentioned above and poorer than normal coal (up to 7% ash instead of 5% ash content). However, in spite of these limitations most of the objectives of the test program could be accomplished satisfactorily due to the excellent cooperation of the plant personnel.

Table 4, Appendix A, presents a summary of the operating and emission data recorded for each test run. Flue gas samples were taken from the centers of six equal areas from each of the two ducts ("A" and "B") between the economizer and the hot-side precipitator. Sixteen measurements were made of each gaseous component during each 32 minute "steady state" test run.

Figure 3-10 is a plot of ppm NO_x (3% O_2, dry basis) vs burner nozzle tilt (degrees from horizontal). The number within the symbols indicate the test run. Straight lines were drawn through the data points obtained from similar firing patterns to indicate the relationship between NO_x emission and degree of burner tilt. Baseline operations (normal firing pattern with OFA ports closed) resulted in 235 ng/J (410 ppm) NO_x when operating normally at -15^o to -20^o burner tilts. Horizontal burner operation reduced NO_x emissions by 18% to 196 ng/J (336 ppm), (Run 5) while lowering burner nozzle tilts to -26^o increased NO_x emissions to 262 ng/J (448 ppm) (Run 3), or 9% above baseline operation.

As expected, operation of the overfire air registers had a large effect on NO_x emission levels. The three lines on Figure 3-10 drawn through data from S_1 operation (closed OFA ports), S_3 (25% open OFA ports) and S_4 (50% open OFA ports), respectively, indicate the reduction of NO_x emission levels as OFA port registers are opened. Figure 3-11 is a plot of ppm NO_x emissions vs the percent open OFA registers for the data from test runs conducted at the normal operating range of -15 to -20^o burner nozzle tilts. The solid line drawn through these data points indicates that NO_x emissions are reduced sharply from 238 ng/J (407 ppm) with overfire air ports closed (actually, 5% open for cooling purposes), to 209 ng/J (358 ppm) with OFA ports 25% open to 169 ng/J (289 ppm) with 50% open OFA ports to a level of 154 ng/J (264 ppm) NO_x emissions when operating with 75 or 100% open OFA ports. Thus, a 36% reduction in NO_x emissions levels from baseline operations was obtained through the use of overfire air ports. Additional improvements would be expected with low excess air operation and raising the burner nozzle tilt angles closer to a horizontal position.

Excess air levels were maintained within "normal" levels during the entire test period at Colorado Public Service Company's request to avoid possible slagging problems. Consequently, test run average flue gas O_2 measurements varied within the narrow range of 3.5% to 4.4% making meaningful correlations of NO_x vs O_2 difficult. However, as commonly found in tangentially fired boilers, average O_2 and NO_x measurements from one duct (A) were consistently lower than those for the other duct (B) on each test run. This situation provided a means for correlating NO_x levels with O_2 levels within the test runs. Figure 3-12 is a plot of ppm NO_x vs O_2 data by flue gas duct for test runs 22 through 31. O_2 measurements in Duct B averaged 2.2% higher than in Duct A, while NO_x measurements in Duct B were 15.8 ng/J (27 ppm) higher than in Duct A. Although these data do not represent the full NO_x reduction potential of low excess air operation, they indicate directionally the improvements that might be obtained.

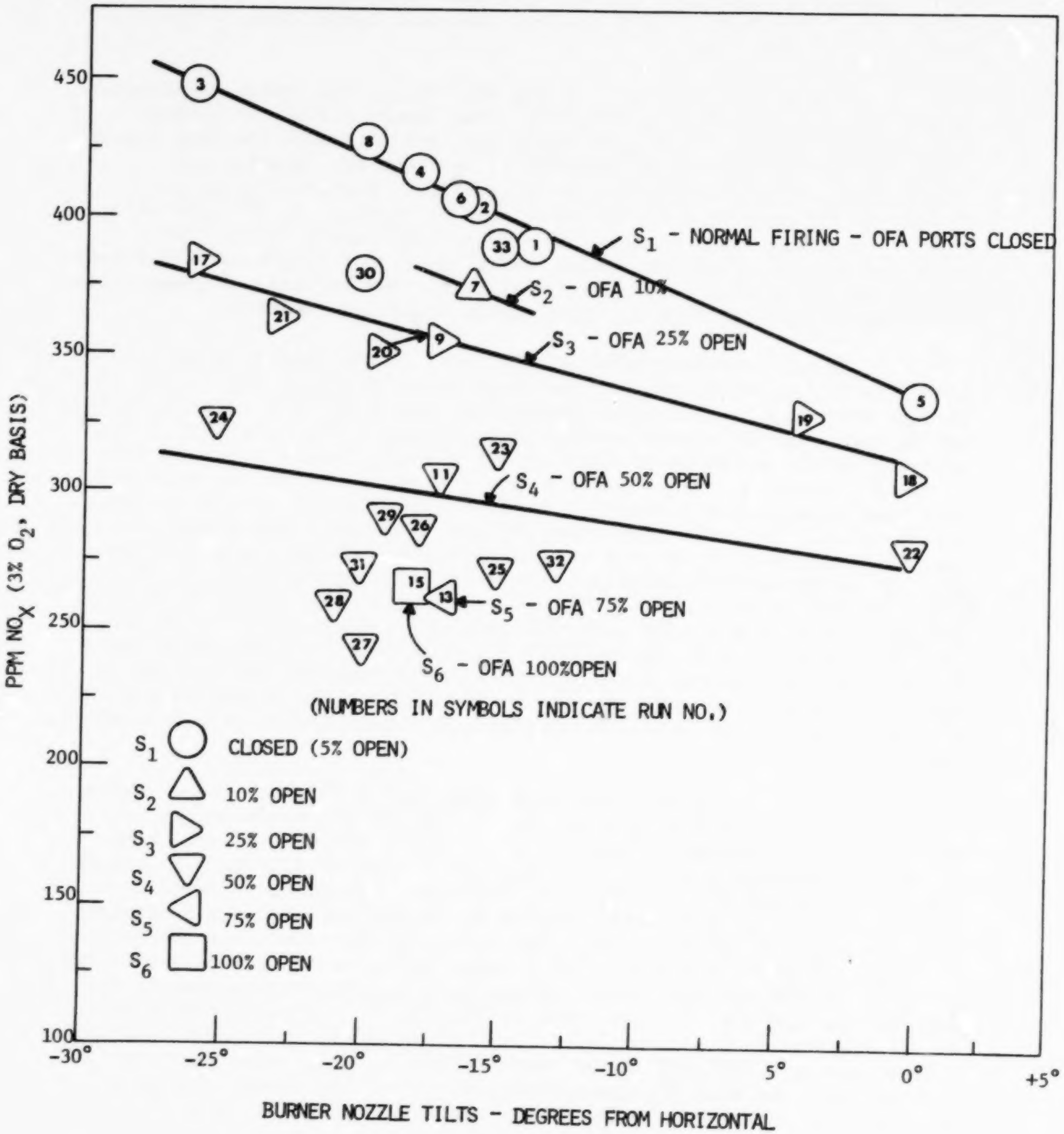

Figure 3-10. Effect of burner nozzle tilt on NO_x emissions from Comanche No. 1 unit.

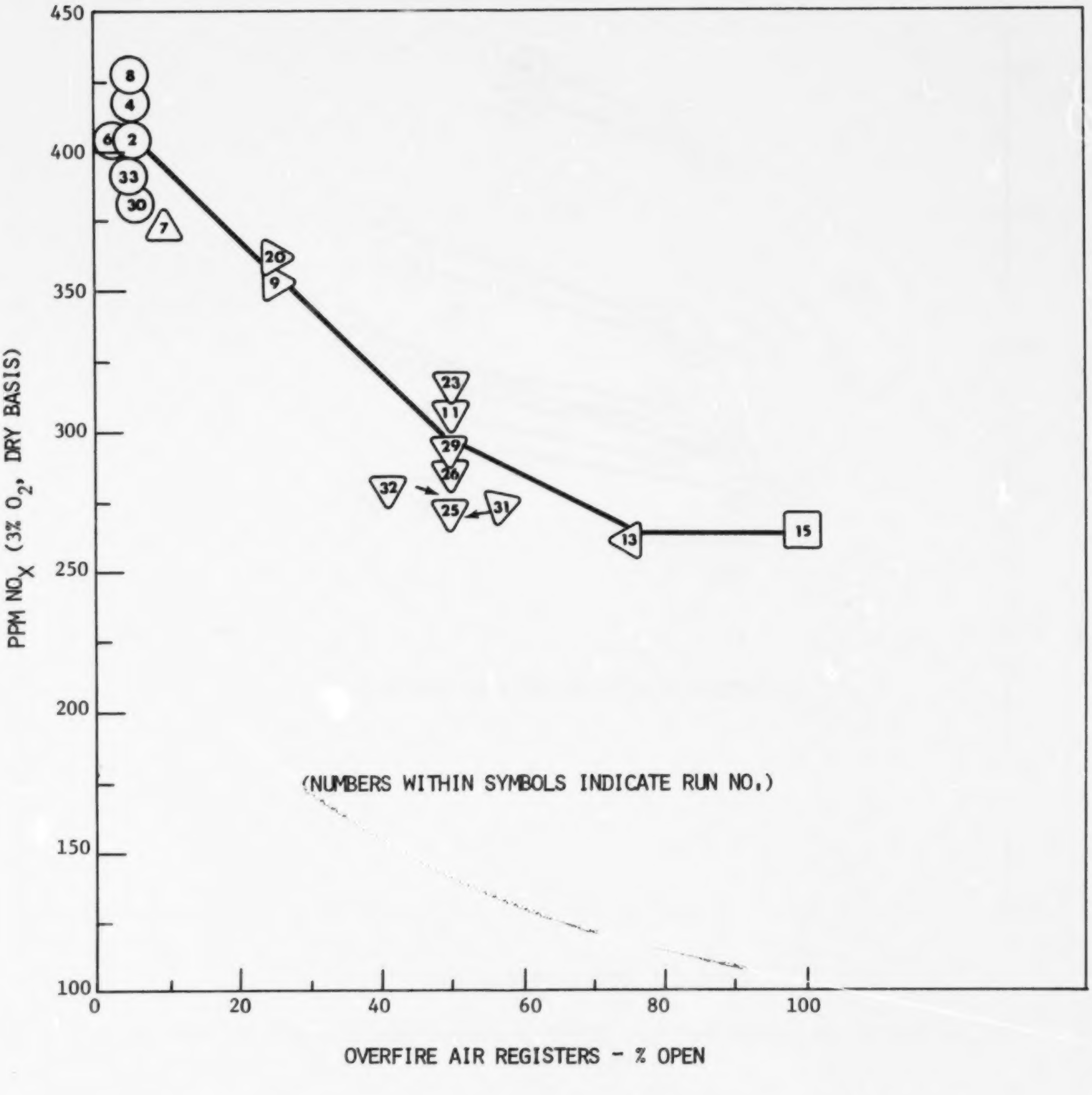

Figure 3-11. Effect of overfire air damper setting on Comanche No. 1 unit NO_x emissions.

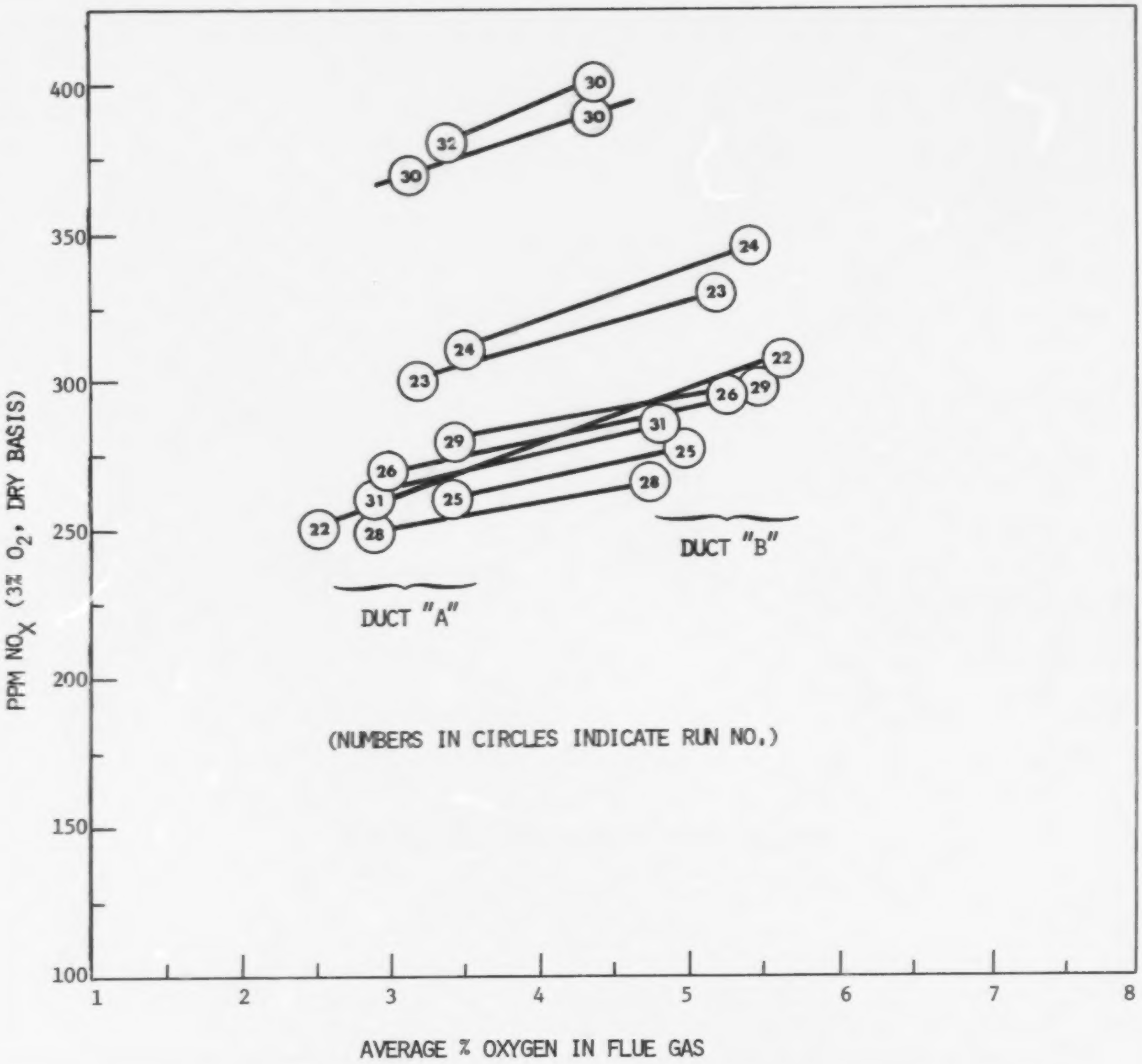

Figure 3-12. NO_x emissions vs. flue gas oxygen measurements on Comanche No. 1 unit.

3.1.5 Barry Station, Boiler No. 2 (Alabama Power Company)

Alabama Power Company's Boiler No. 2 at the Barry Station was the third boiler to be tested in our current field test program. There were two major reasons for selecting this boiler. First, it is one of very few boilers that has been retrofitted with overfire air ports for NO_x emission control. The second reason for selecting this boiler was that it is capable of firing gas (up to 40% of full load), coal and mixed fuel firing. No other boiler in the United States is known to have these combined capabilities. Figure 3-13 is a side elevation view of this boiler.

Barry Station, Unit No. 2 is a natural circulation, balanced draft boiler which fires coal through four elevations of tilting tangential fuel nozzles. Each elevation of burners is fired by a pulverizer. The steam capacity at maximum continuous rating is 408,000 kg/hr (900,000 lbs/hour) main stream flow with a superheat outlet temperature and pressure of 811 K (1000°F) and 272 kPa (1875 PSIG), respectively. Superheat and reheat temperatures are controlled by burner tilt and water spray desuperheating. The furnace is 11.63 m (38 feet 2 inches) wide and 8.57 m (28 feet 1-1/4 inches) in depth. Two wind boxes (upper and lower) feed secondary air through 10 compartments (4 coal and 6 auxiliary) located at the four corners of the furnace. Vertical burner spacing is 1.5 m (4' 11") from center line to center line between elevations 1 to 2 and 3 to 4 with 2.29 m (7' 6") spacing between elevations 2 and 3. Overfire air ports were designed to supply about 20% of total air through new ducts located at each corner at 2.44 m (8 feet) above the upper fuel zone as well as through the top two compartments of the upper windbox.

The experimental program was planned to produce required emission and operating information on this unusually flexible boiler from a minimum number of test runs. The program was divided logically into three experimental blocks, one at full load and two at reduced loads. The prime objectives of the full load (130 MWe) block were to measure NO_x emissions under baseline and modified combustion operation while firing 100% coal (Alabama and Illinois) as well as mixtures of gas and coal up to the maximum gas firing capability of the boiler under both normal and overfire air operation. Test runs to evaluate the effect of excess air level, burner nozzle tilt and secondary air register settings were also included in the full load experimental block. The major objective of the reduced load block at 95 MWe was to compare the NO_x reduction effectiveness of overfire air port operation with modified staged firing (top row of burners on air only). Ninety-five (95) MWe is the maximum load capability of the boiler with the top mill off. To measure NO_x emissions while firing 100% gas, the test runs of block 3 were conducted at the maximum load possible (55 MWe) while firing gas only.

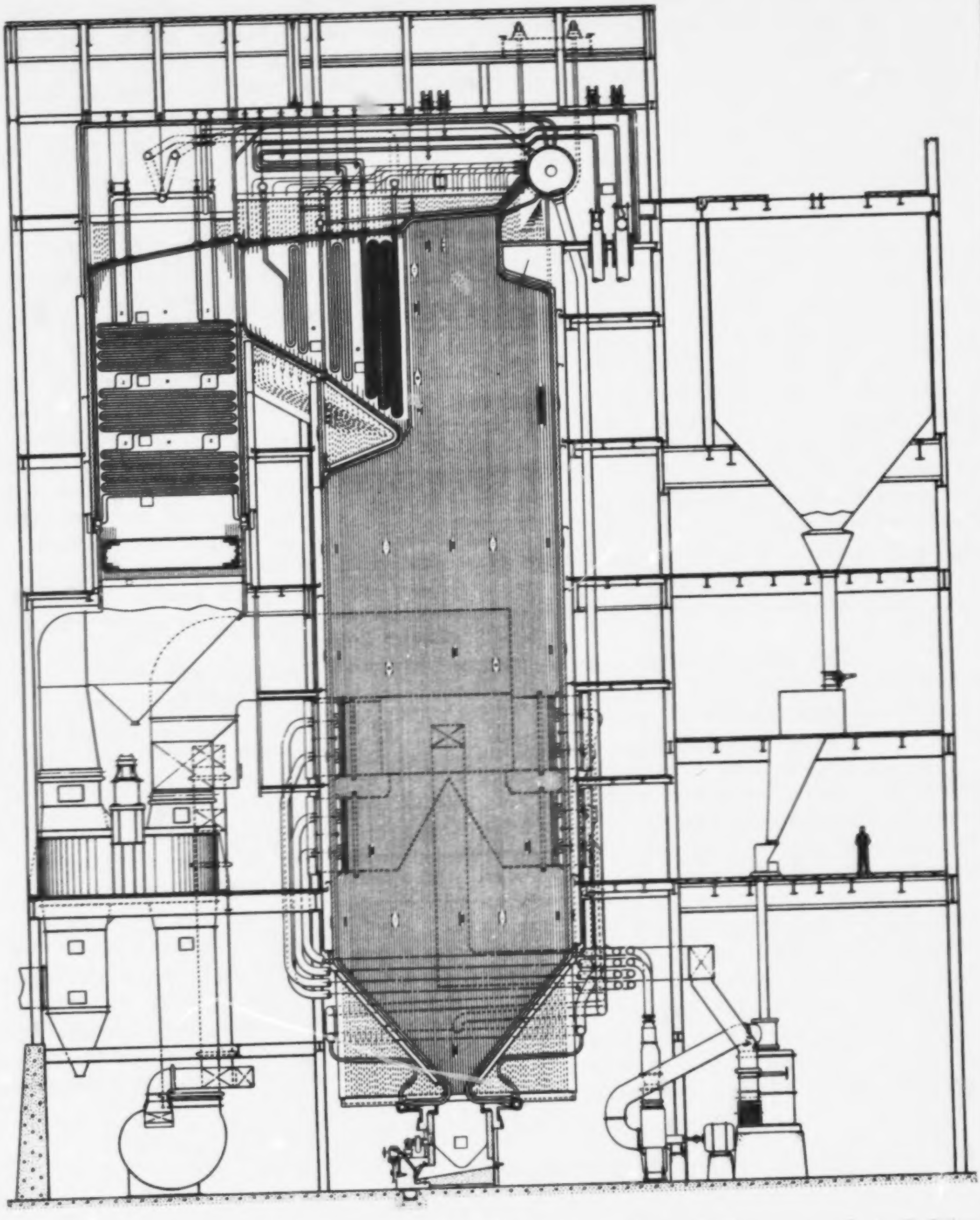

Figure 3-13. Side elevation drawing of Barry No. 2 unit.

Table 5, Appendix C contains a summary of the key operating and emission data for the 37 short-period test runs completed on this unit. Table 3-5 presents the average ppm NO_x emissions (3% O_2, dry basis) and percent oxygen measurements for each test run according to the test program experimental design. The six operating variables (and experimental levels tested) included in the test program were:

1. Gross load [130 MWe (full load), 95 MWe, and 55 MWe]
2. Fuel fired (Alabama coal, Illinois coal, mixed fuel and natural gas)
3. Excess air level (normal and low)
4. Firing patterns (all coal levels firing with NO ports closed, 50% open and 100% open; top row coal off with NO ports closed and 50% open)
5. Burner tilt (horizontal, 20° up and 20° down)
6. Secondary air register setting (coal/auxiliary air at 30/100 and 100/50 % opening)

Full Load Test Data Results - Barry No. 2 Unit

Analysis of the NO_x emission data from the full load test block reveals several significant findings:

1. Full load, baseline operation (normal firing of all 16 burners, burner nozzles tilted down or horizontal, and normal secondary air register settings) produced an average NO_x emission level of 199 ng/J (341 ppm) [3% O_2, dry basis] while firing 100% coal.
2. Staged firing using the special overfire air ports reduced NO_x emissions by 10 to 20% from baseline operation at the same excess air levels. 100% open overfire air ports produced slightly lower NO_x emissions than 50% open operation (227 ppm vs 238 ppm).
3. Excess air level was the most significant single operating variable affecting NO_x emission levels. NO_x emissions were reduced through low excess air operation by 43% to 115 ng/J (196 ppm) under normal (S_1) firing operation, by 39% under staged firing operation, S_2 (50% open overfire air ports) and by 29% under staged firing operation S_3 (100% open overfire air ports). The solid regression lines on Figure 3-14 indicate the relationship between ppm NO_x and the average oxygen content in the flue gas for these three firing patterns while firing 100% coal and operating with horizontal or down burner tilts and normal secondary air register settings.
4. Normal secondary air operation (30% open coal air and 100% open auxiliary air registers) produced an average of about 10% lower NO_x emissions than reversed secondary air operation (100% coal air and 50% open auxiliary air registers) when firing 100% coal.

TABLE 3-5

TEST PROGRAM EXPERIMENTAL DESIGN - BARRY NO. 2 UNIT
(RUN NO., AVERAGE % O_2 AND AVERAGE PPM NO_x-3% O_2, DRY BASIS)

			L_1-Full Load-130 MWe								L_2-95 MWe		L_3-55 MWe			
			F_1-Coal-Alabama		F_2-Coal-Illinois		F_3-.8 Coal 0.2 Gas		F_4-.6 Coal 0.4 Gas		F_2-Coal-Illinois		F_2-Coal-Kentucky		F_5-Nat'l. Gas	
		% Open	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1 Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low	A_1-Nor.	A_2-Low
S_1-Normal Firing: NO Ports Closed, 16 Burners Firing Coal	T_1-Hor. Burner Tilt	D_1-30Coal 100% Aux			㉖5.4% 345 ㉛4.3% 314		㉗4.5% 206		㉑3.9% 168		㉕7.3% 452		⑬8.8% 284	⑭6.9% 254	⑮9.2% 122	⑯7.3% 97
		D_2-100Coal 50 Aux				㉞3.8% 299										
	T_2-+20°	D_1-30Coal 100 Aux			㉜4.0% 320											
	T_3-20°	D_1-30Coal 100 Aux	①4.9% 365	68.1% 196	㉝3.9% 273											
S_2-NO P. 1/2 Open 16-Coal	T_1-Hor.	D_1-30Coal 100Aux	②4.8% 294 *	53.5% 182 *			㉘5.1% 186		㉒4.6% 184		⑦7.1% 411	⑧4.8% 253				
S_3-NO Ports 100% Open 16 Burners Firing Coal	T_1-Hor.	D_1-30Coal 100 Aux			㊳4.7 243		㉙5.0% 184	㉚4.9% 182	㉓4.9% 182	㉔3.7% 143						
		D_1-100Coal 50 Aux				㉟4.0% 233										
	T_2-+20°	D_2-100 Coal 50 Aux				㊱4.1% 274										
	T_3--20°	D_1-30Coal 100 Aux	③4.7% 265	④3.8% 189		㊲4.0% 218 **										
S_4-Top Row Air 12 Burn.-Coal	T_1-Hor.	D_1-30Coal 100 Aux									⑨7.1% 330	⑩4.6% 212				
S_5-NO 1/2 Open Top Row Air 12 Burn.-Coal	T_1-Hor.	D_1-30Coal 100 Aux									⑪6.8% 272	⑫4.3% 192				

* Test runs 2 and 5: burner tilt -20°

** Test run 37: D_2 100 coal and 50 auxiliary air damper settings

5. Burner nozzle tilt over the range of -20° to horizontal produced no consistent change in NO_x emission levels. However, raising burner nozzle tilts to +20° resulted in significantly higher NO_x emission levels. This effect can be explained by the fact that the overfire air directional dampers were fired at -11° and thus the effectiveness of staged combustion was reduced with raised burner tilts due to reduced separation of the overfire air from the main combustion zone.

6. Mixed fuel firing at full load reduced NO_x emissions significantly but not linearly. Figure 3-15 is a plot of ppm NO_x (3% O_2, dry) vs percent coal in the fuel fired (on a heat release basis) for comparable full load test runs under normal firing, S_1, and staged firing (S_2 and S_3) operations. Firing with 80% of the heat release from coal reduced NO_x emissions by an average of 30%, while firing with 60% coal resulted in an average of 32% NO_x reduction from 100% coal firing over the three firing patterns. Thus, within the range of full load, mixed fuel firing capability of this boiler, the data indicates that replacing coal with gas fuel lowers NO_x in the direction of full gas firing but the relationship is not linear. As discussed below, at reduced load (55 MWe), firing with 100% gas reduced NO_x emissions from 157 to 64 mg/J (269 to 110 ppm) (60%) compared to 100% coal firing. A comparable linear relationship at full load would thus be a 12% reduction in NO_x emissions when firing 80% coal-20% gas mixture and a 24% reduction when firing a mixture of 60% coal-40% gas.

Reduced Load Tests

Earlier, we discussed the necessity for conducting two test program blocks at reduced load. The first block (comprising seven test runs under 100% coal firing) was conducted in order to obtain information on the NO_x emission reduction effectiveness of staged combustion using overfire air ducts compared to modified staged combustion operation where the top tier of burners are operated on air only. Since the maximum capacity of the boiler with the top mill inactive is 95 MWe, all of these runs were made at this load for purposes of comparison. The second block (four test runs) was conducted at the maximum load capacity of this boiler (55 MWe) when firing 100% gas.

Reduced load test runs at 95 MWe were conducted under normal, all burners firing operation and at three different staged firing patterns: S_2, overfire air port dampers set at 50% open and all four levels of burners firing; S_4, overfire air port dampers closed (cooling air only) with top tier of burners on air only; and S_5, overfire air dampers 50% open and top tier of burners on air only.

The dashed lines on Figure 3-14, labeled S_2, S_4 and S_5 connect the normal excess air and low excess air NO_x emission data points for each of these staged firing patterns. These results can be summarized as follows:

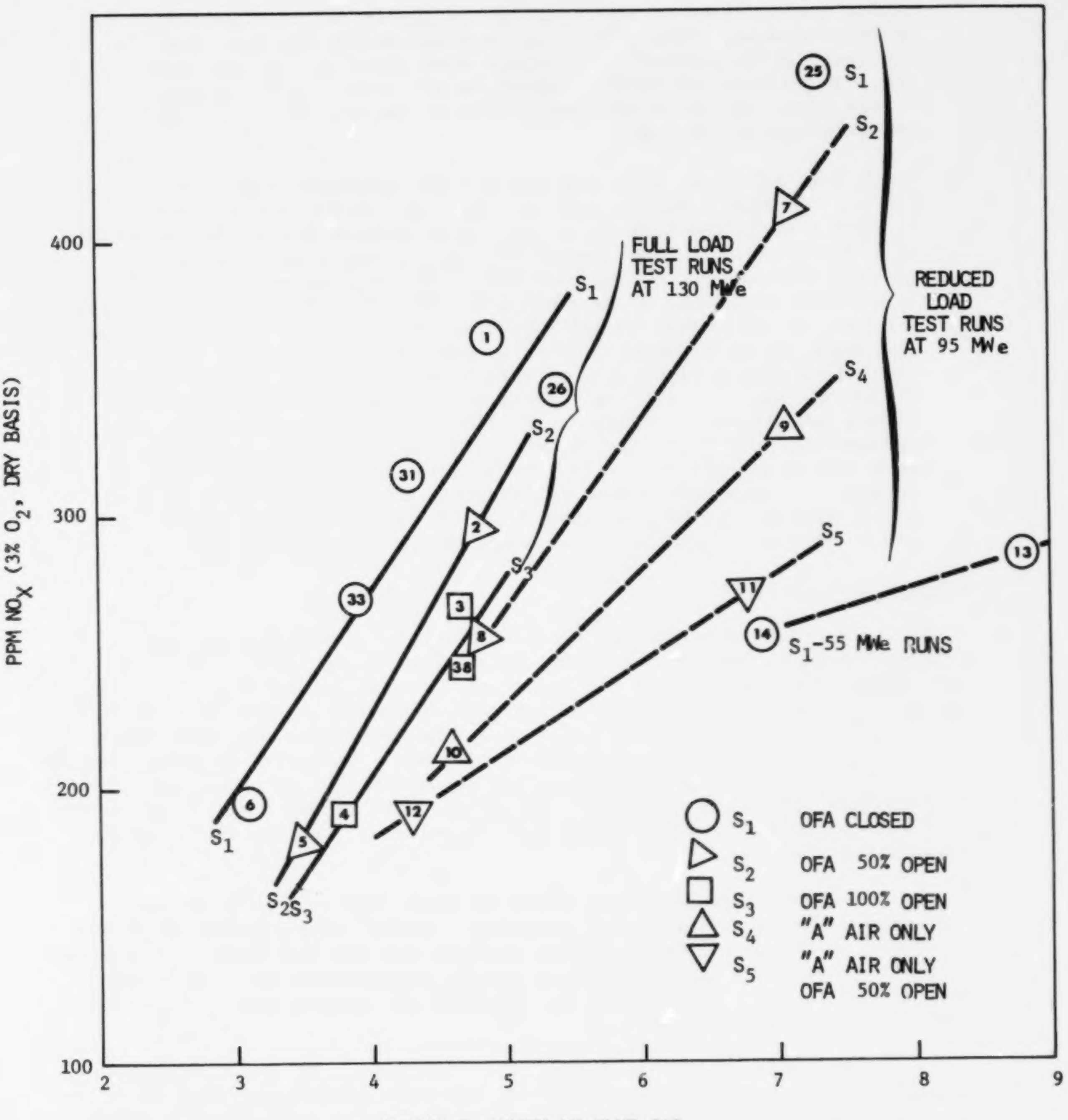

Figure 3-14. NO_x emissions vs % O_2 in flue gas for 100% coal fired test runs on Barry No. 2 unit.

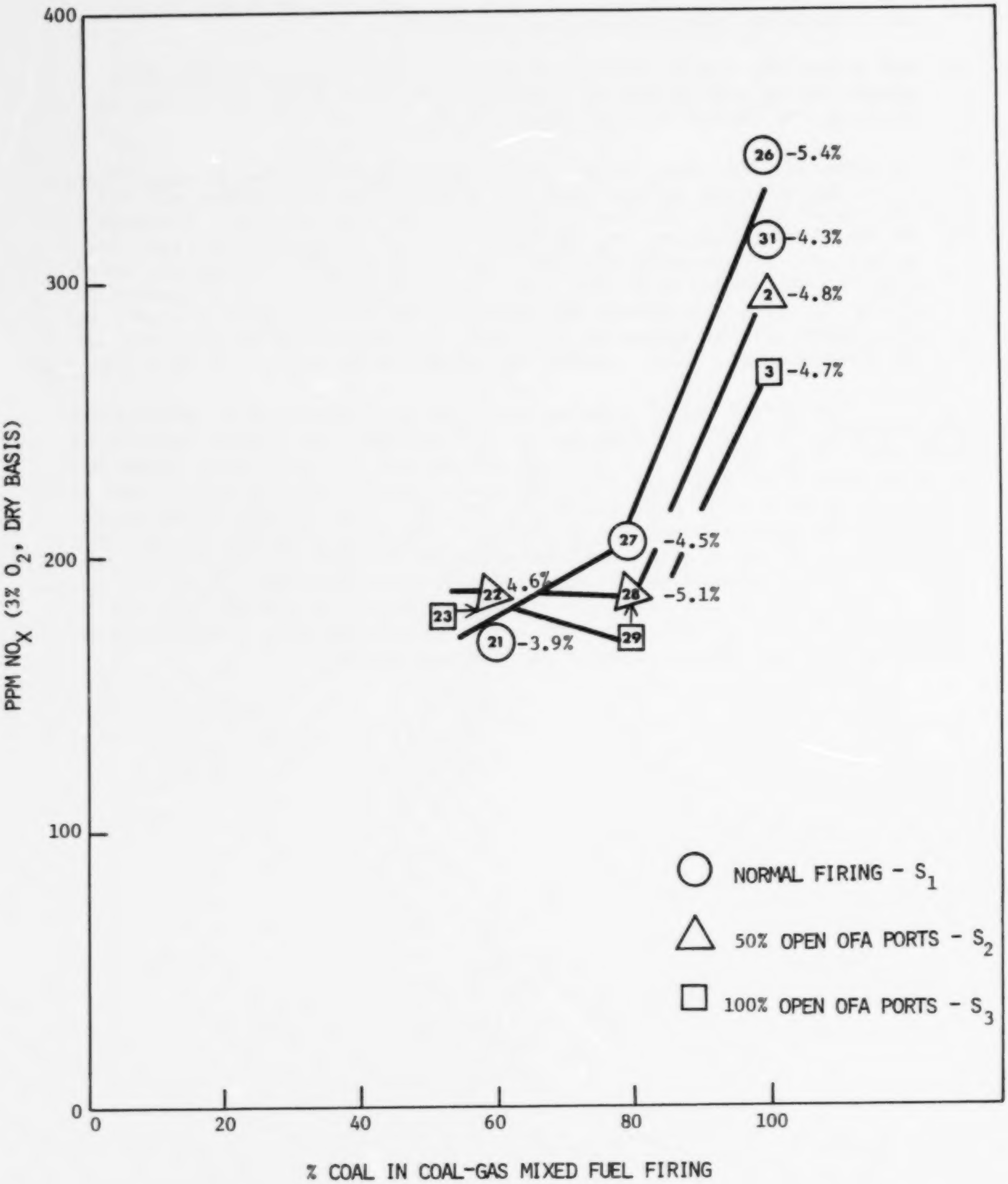

Figure 3-15. NO_x emissions vs % coal in coal-gas mixed-fuel firing operation on Barry No. 2 unit.

1. Baseline NO_x emissions were 264 ng/J (452 ppm) at the higher excess level required under reduced load operation.

2. Low excess air operation reduced NO_x emissions sharply in all three staged firing configurations compared to normal excess air levels as shown by the dashed lines of Figure 3-14.

3. As expected, all three staged firing operations resulted in significantly lower NO_x emission levels, with the combined use of overfire air and top row of burners on air only producing the best results. Compared to the 95 MWe, baseline NO_x emission level of 264 ng/J (452 ppm), low excess air, S_2 operation (overfire air ports ½ open) reduced NO_x emissions by 44% to 148 ng/J (253 ppm); low excess air, S_4 (top burners on air only) operation reduced NO_x emissions by 53% 124 ng/J (212 ppm) and low excess air, S_5 operation (50% open overfire air ports plus top row of burners on air only) reduced NO_x emissions by 58% to 112 ng/J (192 ppm).

The second set of reduced load test runs (numbered 13 through 16) were designed to supply information on 100% gaseous fuel firing compared to 100% coal firing under both normal and low excess air operation. Under normal operation at 55 MWe load, coal was fired through the bottom two rows of burners with relatively high excess air levels. Baseline NO_x emissions of 166 ng/J (284 ppm) were reduced to 148 ng/J (254 ppm) with low excess air operation. 100% gas firing operation produced 71 ng/J (122 ppm) NO_x under normal excess air levels and 57 ng/J (97 ppm) when using low excess air operation. Thus, at this low load, gas firing resulted in a 57% NO_x emission reduction under normal air operation and a 62% NO_x emission reduction under low excess air operation, compared to 100% coal firing.

3.1.6 Morgantown, Boiler No. 1 (Potomac Electric Power Company)

Potomac Electric Power Company's, Boiler No. 1 at Morgantown, Md. was the fourth boiler tested in the current field test program. This boiler was selected, with the assistance of Combustion Engineering Company, because it represents modern design practices and has the capability of firing oil, pulverized coal or mixtures of these two fuels.

Morgantown Boiler No. 1 is a 575 MWe, Combustion Engineering tangentially fired, twin furnace boiler. Five pulverizers feed 40 burners arranged at five levels (from A pulverizer feeding the top 8 burners to E pulverizer feeding the bottom 8 burners). Thirty-two oil burners are positioned at the four levels (8 per level) between the five pulverized coal burner levels, i.e., between A and B, B and C, C and D and D and E. The furnace has a volume of 8269 m^3 (292,600 cubic feet), a width of 19.25 m (63.15 feet) and a length of 10.8 m (34.45 feet). Full load steam rate is 1,928,000 kg/hr (4,250,000 pounds/hour) at 814 K (1000°F) superheat temperature and 555 kPa (3810 PSIG) pressure.

Table 6 of Appendix C contains a summary of the operating and emission data from the 27 test runs completed on this boiler. Table 3-6 presents the results arranged according to the test program experimental design. The five operating variables (and experiment levels) included in the test program were:

1. Gross load (full load - 575 MWe, and reduced load - 300 MWe)
2. Excess air level (normal, low, and high)
3. Fuel mixture fired (100% coal to 100% oil)
4. Burner tilt (horizontal, +15°, -15°)
5. Firing pattern (normal firing - S_1, and staged firing - S_2)

Flue gas measurements of average O_2 and NO_x concentrations are included in Table 6 of Appendix C, as well as the calculated percent stoichiometric air to the active burners. The flue gas sampling system consisted of four probes, each containing short, medium and long sampling tubes positioned at the centers of 12 equal areas in the ducts between the economizer and the air heaters. Composite gas samples from each set of probes were analyzed and recorder in turn over four complete cycles, resulting in 16 measurements of each gaseous component in each test run.

The NO_x measurements made are plotted in three separate figures using identical coordinate scales to show the results obtained under different local conditions and firing patterns. Figure 3-16 is a plot of ppm NO_x (3% O_2, dry basis) vs. % coal (on a heat release basis) for coal-oil conditions (no overfire air). Figure 3-17 is a plot of test runs conducted under full load, staged firing (air only at top pulverized coal burner level) conditions. Figure 3-18 is a plot of test runs conducted at reduced load (about 300 MWe) under both normal and staged firing conditions. The

TABLE 3-6

TEST PROGRAM EXPERIMENTAL DESIGN - MORGANTOWN BOILER NO. 1

(Run No., Average % O_2 and Average PPM NO_x - 3% O_2, Dry Basis)

			L_1 - Full Load (575 MWe)				L_2 - Reduced Load (300 MWe)				
			F_1 - 93% C 7% O *	F_2 - 73% C 27% O	F_3 - 45% C 55% O	F_4 - 22% C 78% O	F_1 - 100% C 0% O	F_2 - 63% C 37% O	F_3 - 50% C 50% O	F_4 - 20% C 80% O	F_5 - 0% C 100% O
S_1 - Normal Firing Pattern	A_1 - Normal Excess Air	T_1 - Hor. Tilt	⑰ 4.9% 552	⑬ 4.4% 593	⑦ 4.5% 525	① 4.4% 458	㉕ 6.5% 544	㉔ 6.8% 460	(22A) 6.9% 408		(21A) 5.9% 247
		T_2 - +15° Tilt			⑧ 4.7% 553						
		T_3 - -15° Tilt			⑨ 4.7% 568						
	A_2 - Low Air	T_1 - Hor. Tilt	⑱ 3.8% 549	⑭ 3.4% 511	⑩ 2.8% 502	② 2.1% 386	㉖ 6.3% 515				
S_2 - Staged Firing	A_1 - Nor. Air	T_1 - Hor. Tilt		⑮ 4.7% 403	⑪ 4.5% 465	③ 4.6% 375			㉒ 5.4% 300		⑲ 5.1% 165
	A_2 - Low Excess Air	T_1 - Hor. Tilt			⑫ 3.1% 423	④ 3.3% 310					⑳ 4.2% 149
		T_2 - +15° Tilt				⑤ 3.4% 334					
		T_3 - -15° Tilt				⑥ 3.1% 314					

* Fuel fired - % coal and % oil on heat release basis.

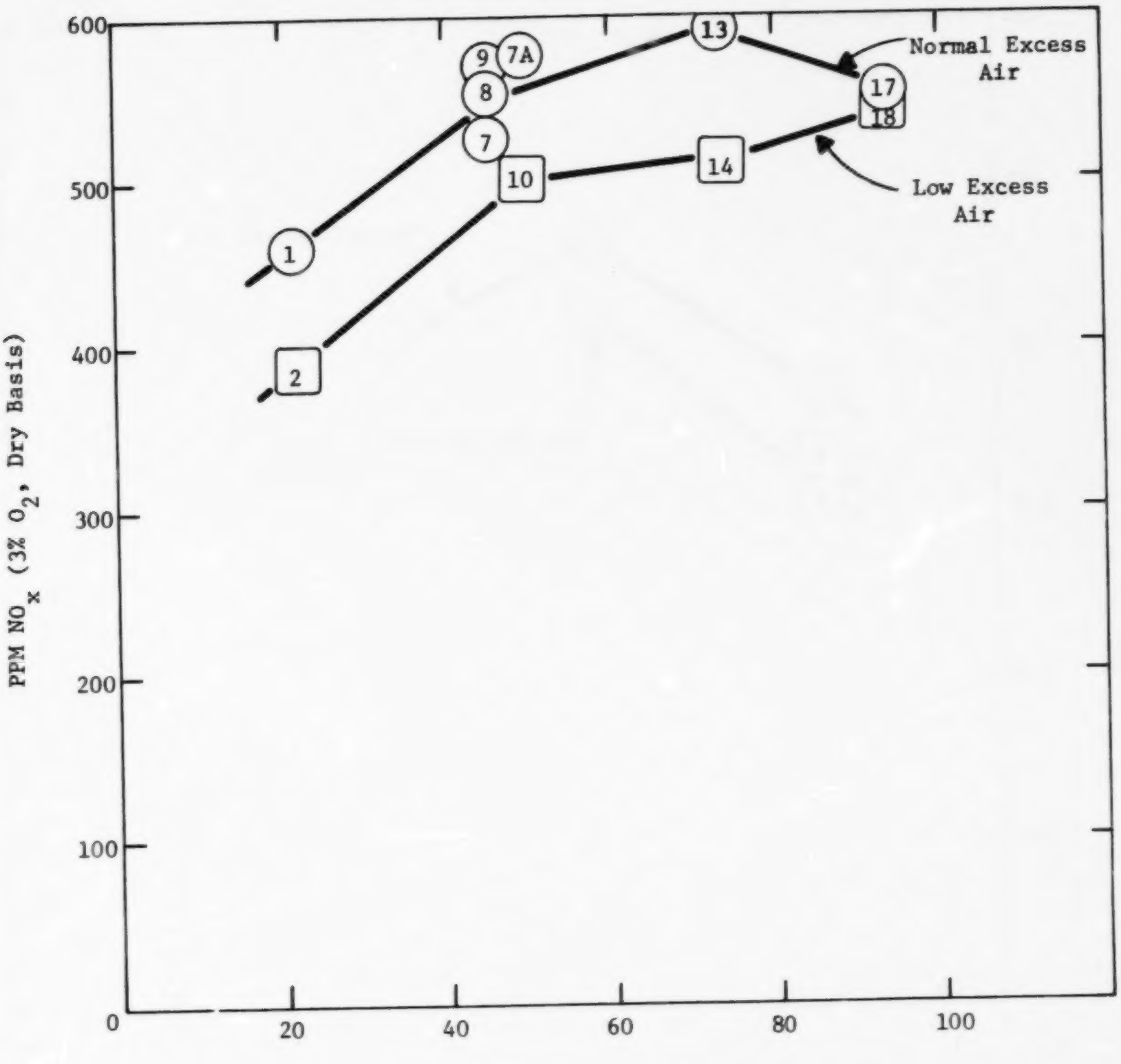

Figure 3-16. NO_x emissions vs % coal in oil-coal mixed-fuel, normal firing operation on Morgantown No. 1 unit.

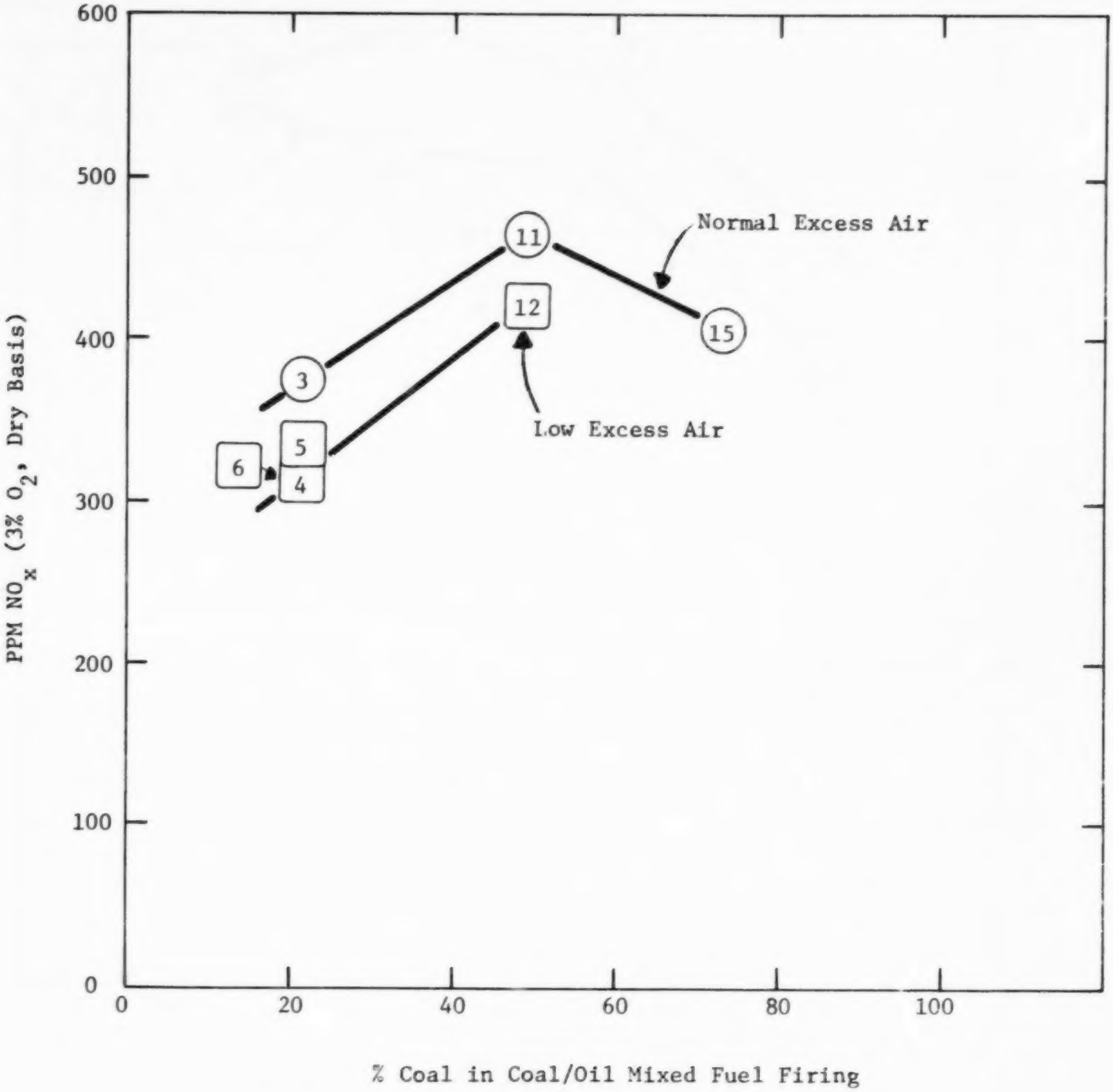

Figure 3-17. NO_x emissions vs % coal in coal/oil mixed fuel, staged firing operation on Morgantown No. 1 unit.

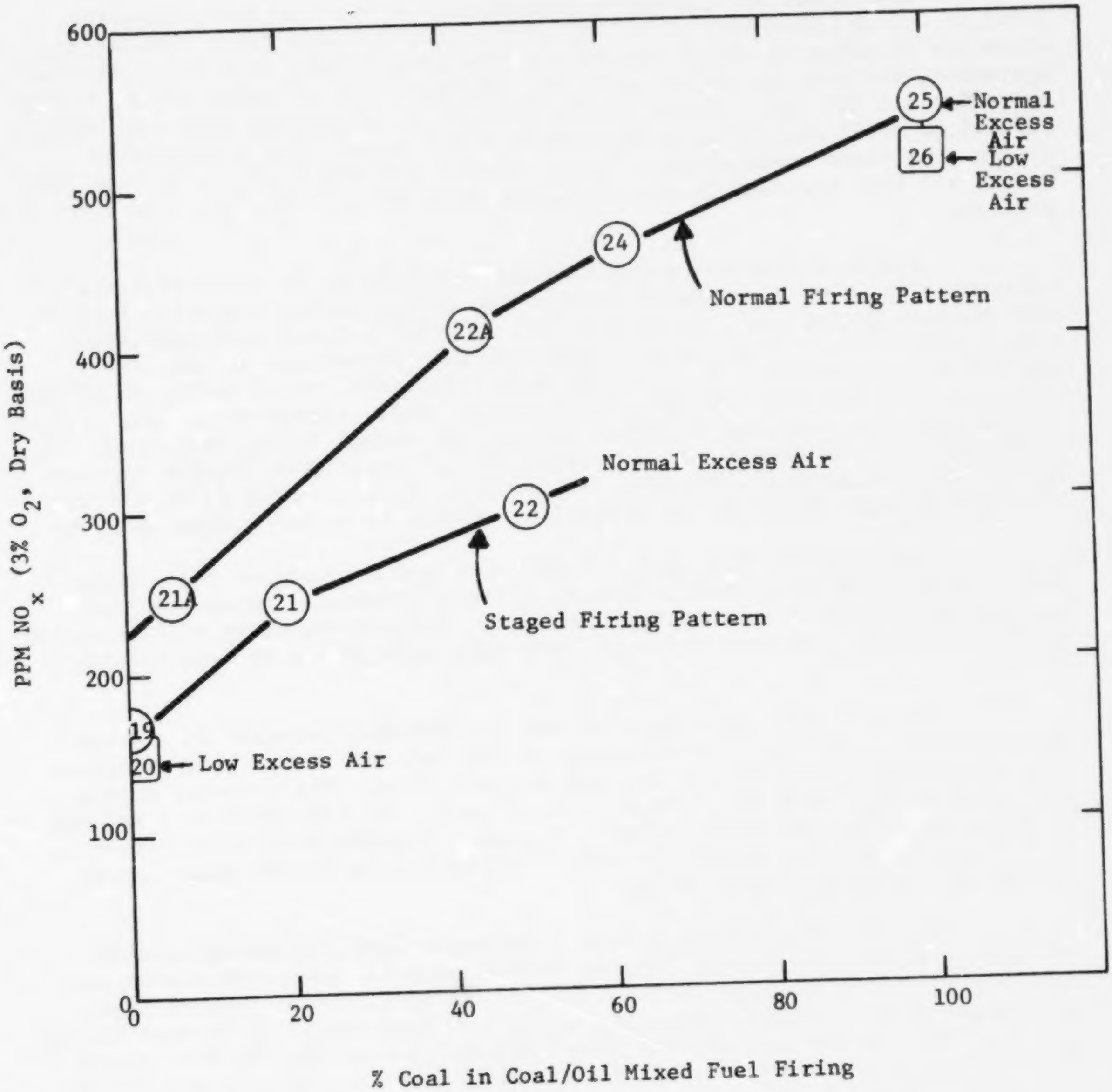

Figure 3-18. PPM NO_x emissions vs % coal in coal/oil mixed-fuel firing operation at reduced load on Morgantown No. 1 unit.

numbers shown within the circles (normal excess air operation) or squares (low excess air operation) indicate test run indentification numbers. The conclusions reached from analysis of the data are as follows.

Low excess air operation (established by the maximum permissible level of 200 ppm CO emission for any single probe) consistently reduced NO_x emissions compared to normal excess air operation. Under full load (575 MWe) operation, the average reduction in NO_x emissions was 10% under normal firing operation and 18% under staged firing operation. At reduced load (300 MWe), reductions of 5% and 10% were experienced under normal firing and staged firing conditions respectively. Lines connect the normal excess air and low excess air test run data points in Figures 3-16 and 3-17 to show this comparison.

Staged firing operation (top mill burners on air only) produced substantially lower NO_x emission levels than normal firing operation (top mill burners firing coal) under both full load and reduced load operation over a wide range of fuel mixture compositions. Reductions of 18%, 19% and 32% were experienced at full load when firing with mixed fuels containing 22% coal, 49% coal and 73% coal, respectively, under normal excess air, staged firing operation compared to normal excess air, normal firing operation. The combination of low excess air and staged firing resulted in further improvements. At reduced load (300 MWe), NO_x emission reductions of 26 to 40% were obtained through staged firing operation compared to normal firing operation.

Changing the tilt angle of the coal injected nozzles had a minor effect on NO_x emissions when firing mixed fuel, presumably because the oil burners were fired in a horizontal position. Horizontal burner tilts resulted in NO_x emissions that were about 6% lower than with 15° up or down tilting burners.

Reduced load operation (300 MWe vs. 575 MWe) resulted in lowered NO_x emissions. However, the magnitude of the reduction was highly dependent upon the amount of oil in the coal-oil mixture fired. While firing mostly coal (93% at full load and 100% at reduced laod), NO_x emissions were reduced on the average by only four percent. However, reducing load while firing 22 to 55% oil in oil/coal mixtures, reduced NO_x emissions by 26% under normal firing and 35% with staged firing.

NO_x emission levels generally increased with increasing amounts of coal in mixed fuel firing. Figure 3-18 shows this trend over almost the full range of fuel mixtures under normal firing operation at reduced load. A straight line through the NO_x data point from test run 25 (100% coal firing) and test run 21A (5% coal firing) does not pass through the NO_x data points for intermediate mixtures of coal-oil fuel. Thus, test run 22A (43% coal - 57% oil fired) measured 13% higher NO_x emissions and test run 24 (62% coal - 38% oil fired) produced 9% higher NO_x emissions than would be expected from a linear relationship calculated from 100% coal and 100% oil firing. Figure 3-16 shows a pronounced departure from a linear relationship for mixed fuel firing over the range from 22% coal to 93% coal. Increasing the percentage of coal in the coal-oil mixture from 22% to 45% or 49% resulted in significantly increased NO_x emissions (by 58 ng/J, or 93.5 ppm) but little change in NO_x emissions resulted from further increases in the percentage of coal fired. During the test period this boiler had limited fuel burning capability, and therefore, full load test runs on 100% coal or 100% oil could not be run. Only 21 of the 32 oil burners were operational due to mechanical problems, and therefore, 22% of the heat release had to be supplied from coal. At the same time, coal supplies were short and some coal handling equipment could not be operated. Consequently, plant management had to limit the length of time that high coal mixtures could be burned as well as the maximum coal content of the mixed fuel.

In summary, it was found that most of the operation variables included in the experimental program had significant effects on NO_x emission levels. Low excess air operation reduced NO_x emissions by about 10% for a wide range of coal/oil mixtures at full and reduced load. Staged firing operation resulted in 20 to 30% NO_x emission reductions over a wide range of coal/oil fuel mixtures. Combined low excess air and staged firing operation reduced NO_x by 30 to 40%. Tilting burners over the range of +15° to -15° produced minor changes in NO_x levels with horizontal levels producing the lowest NO_x emission levels. Increasing the proportion of coal in simultaneous oil/coal firing increased NO_x emission levels nonlinearly under both normal and staged firing operation. The NO_x emission level increase was higher in changing from 0% to 50% coal, than the NO_x emission increase when changing from 50% to 100% coal fuel. It is likely that such behavior is exhibited because of the changing relative contributions of thermal NO_x and fuel NO_x to the total emissions.

3.1.7 Mercer Station, Boiler No. 1
Public Service Electric and Gas Company (New Jersey)

Mercer Unit No. 1 is a twin furnace, front-wall fired, wet-bottom Foster Wheeler boiler. This unit was selected for testing because of its flexibility for combustion modification, and to determine the side-effects of such modifications on a wet-bottom unit. The boiler has 3579 m^2 (38,526 ft^2) of furnace heating surface, a furnace volume of 5333 m^3 (188,332 cubic feet), with each furnace measuring 11.95 m (39 feet 2 1/2 inches) in width and 7.99 m (26 feet 2 1/2 inches) in depth. Maximum continuous rated steam flow is 934,000 kg/hr (2,060,000 lb/hr) at 348 kPa (2400 PSIG) pressure and 867 K (1100°F) superheat steam temperature and 839 K (1050°F) reheat steam temperature. Three ball-type pulverizers feed the 24 burners arranged in three rows of four burners in each of the two twin furnace front walls. The pressurized furnaces are equipped with flat floors and slag-taps.

Table 3-7 contains a summary of the operating and emission data for each of the 12 test runs conducted at full load during the Phase I test program. Operating variables listed are gross load (MWe), excess air level (normal and low), firing pattern (S_1-normal and S_2-biased firing, i.e. top row of burners fuel-lean with middle and bottom burner rows fuel-rich), and secondary air register settings (80% open and 50% open). Gaseous measurements of % O_2 and ppm NO_x (3% O_2, dry basis) are listed for the reheat furnace outlet, the superheater furnace outlet, and for boiler average. Table 7, Appendix C, contains a summary of the operating and emission data for all 36 test runs completed on this unit.

Table 3-8 contains a summary of the operating and emissions data for each of the 21 reduced load test runs completed in the Phase I test program. Operating variables were gross load (MWe), excess air level (normal and low), firing pattern (S_1-normal, S_3-staged, and S_4-top mill air and coal off), and secondary air registers (off and opened to: approximately 15%, 50% and 80% open). Normal secondary air register setting is about 80% open while 15% open is used at initial firing and closing down to about 40 to 50% open is an intermediate setting.

Table 3-9 presents the test data (run number, % oxygen, and ppm NO_x) according to the partially replicated, factorial experimental design conducted for the Phase I test program. Repeat test runs were conducted corresponding to the conditions of runs No. 10, 23, 25, and 26, to provide the data needed for the determination of experimental error under these key test conditions.

Figure 3-19 is a plot of ppm NO_x (3% O_2, dry basis) vs. average % O_2 measured in the flue gas for each test run condition. Lines have been drawn through the data for the normal and low excess air firing for each operating condition (boiler load, firing pattern, and secondary air register setting).

Analysis of these test results indicate that all of the operating variables included in the experimental program had a significant effect on NO_x emission levels. At full load (290 MWe) baseline operation resulted in 809 ng/J (1383 ppm) NO_x emissions. This high NO level is caused by the unusual furnace design of this boiler in which pulverized coal can be burned

TABLE 3-7

SUMMARY OF OPERATING AND EMISSION DATA
(MERCER NO. 1 UNIT)

Date-Run No.	Gross Load (MWe)	Excess Air Level	Firing Pattern (1)	Secondary Air Registers (2)			Gaseous Measurements								
							Reheat			Superheat			Boiler		
				Top	Mid	Bot	% O_2	ng/J	PPM NO_x	% O_2	ng/J	PPM NO_x	% O_2	ng/J	PPM NO_x
12/3-1	296	Normal	S_1-Normal	80%	80%	80%	4.08	751	1284	3.70	867	1482	3.89	809	1383
2	290	Low	S_1-Normal	80%	80%	80%	2.05	637	1098	1.66	699	1196	1.86	670	1147
3	290	Normal	S_2-Biased	80%	80%	80%	3.21	688	1176	3.26	754	1289	3.24	723	1237
4	290	Low	S_2-Biased	80%	80%	80%	1.45	540	924	1.25	538	920	1.35	539	922
12/4-5	288	Normal	S_1-Normal	80%	50%*	50%*	4.06	839	1434	3.78	844	1444	3.92	842	1439
6	285	Low	S_1-Normal	80%	50%*	50%*	2.04	605	1034	1.85	609	1042	1.95	607	1038
7	283	Normal	S_2-Biased	80%	50%*	50%*	4.10	608	1040	3.68	753	1288	3.89	681	1164
8	284	Low	S_2-Biased	80%	50%*	50%*	1.89	495	846	1.62	530	906	1.76	512	876
1A	290	Normal	S_1-Normal	80%	80%	80%	3.60	725	1240	4.60	818	1399	4.10	771	1319
12/5-1B	280	Normal	S_1-Normal	80%	80%	80%	5.02	677	1157	4.78	792	1355	4.90	734	1256
1C	291	Normal	S_1-Normal	80%	80%	80%	3.86	729	1246	3.95	816	1396	3.91	772	1321
1D	292	Normal	S_1-Normal	80%	80%	80%	3.81	715	1223	4.15	807	1380	3.98	761	1302

(1) S_2-Biased Firing: top row of burners fuel-lean with middle and bottom burners fuel-rich.

(2) Secondary air register settings are 80% open at full load and closed down to 40 to 50% open for low load firing.

* Reheat furnace 50% open and superheat furnace 80% open.

TABLE 3-8

SUMMARY OF OPERATING AND EMISSION DATA PSE&G CO. (N.J.), MERCER NO. 1 UNIT

(Reduced Load Test Runs)

Date-Run No.	Gross Load (MWe)	Excess Air Level	Firing Pattern (1)	Secondary Air Registers (2)			Gaseous Measurements								
							Reheat			Superheat			Boiler		
				Top	Mid	Bot	% O_2	ng/J	PPM NO_x	% O_2	ng/J	PPM NO_x	% O_2	ng/J	PPM NO_x
12/8- 23	150	Low	S_4-Top Off	0%	80%	80%	4.91	439	750	5.05	471	805	4.98	455	778
24	151	Normal	S_3-Top Off	0%	80%	80%	6.42	524	897	6.78	535	915	6.60	530	906
26	152	Low	S_3-Staged	80%	80%	80%	4.00	193	330	4.56	206	352	4.28	199	341
25	152	Normal	S_3-Staged	80%	80%	80%	7.95	409	700	8.46	492	841	8.21	451	771
29	155	Normal	S_3-Staged	50%	80%	80%	7.92	480	820	8.08	504	861	8.00	491	840
30	150	Low	S_3-Staged	50%	80%	80%	4.16	288	492	4.82	275	471	4.49	282	482
12/9- 10	219	Low	S_3-Staged	80%	80%	80%	3.51	216	370	3.70	236	403	3.60	226	386
9	218	Normal	S_3-Staged	80%	80%	80%	7.15	473	808	6.41	427	730	6.78	449	769
27	216	Normal	S_3-Staged	50%	80%	80%	6.91	524	896	6.34	477	816	6.62	501	856
28	212	Low	S_3-Staged	50%	80%	80%	3.20	230	394	2.99	195	334	3.10	213	364
20	210	Low	S_3-Staged	15%	80%	80%	2.60	405	692	2.02	311	532	2.31	358	612
19	211	Normal	S_3-Staged	15%	80%	80%	6.32	610	1043	6.25	578	989	6.28	594	1016
12/10-11	238	Normal	S_1-Normal	80%	80%	80%	5.15	641	1096	6.56	688	1176	5.86	664	1136
12	232	Low	S_1-Normal	80%	80%	80%	3.34	592	1012	2.97	600	1026	3.15	596	1019
22	226	Low	S_4-Top Off	0%	80%	80%	3.60	552	944	2.83	542	927	3.22	547	936
12/11-23A	165	Low	S_4-Top Off	0%	80%	80%	4.30	413	707	3.70	422	722	4.00	417	714
26A	161	Low	S_3-Staged	80%	80%	80%	3.53	205	350	4.78	219	374	4.16	212	362
25A	162	Normal	S_3-Staged	80%	80%	80%	6.75	392	670	7.30	414	708	7.02	403	689
12/12-17	236	Normal	S_1-Normal	80%	50%	50%	5.47	643	1100	6.00	687	1174	5.73	665	1137
18	232	Low	S_1-Normal	80%	50%	50%	3.24	602	1029	4.24	720	1232	3.47	661	1130
10A	211	Low	S_3-Staged	80%	80%	80%	2.80	160	275	3.82	222	380	3.31	191	327

TABLE 3-9

TEST PROGRAM DESIGN - MERCER NO. 1 UNIT
(TEST RUN NO., % OXYGEN AND PPM NO_x (3% O_2, DRY BASIS)

		L_1-(290 MWe)		L_2-(220 MWe) (Max. Load-1 Mill Off)		L_3-(155 MWe)	
		A_1-Normal Excess Air	A_2-Low Excess Air	A_1-Normal Excess Air	A_2-Low Excess Air	A_1-Normal Excess Air	A_2-Low Excess Air
S_1-Base (Normal Firing)	R_1-Normal 2nd Air Reg.	① 3.9% 1383	② 1.9% 1147	⑪ 5.9% 1136	⑫ 3.15% 1019		
	R_2-Closed Down 2nd	⑤ 3.9% 1439	⑥ 1.95% 1038	⑰ 5.7% 1137	⑱ 3.5% 1130		
S_2-Biased Firing (Top Burners Lean Fuel)	R_1-Normal 2nd Air Reg.	③ 3.2% 1237	④ 1.35% 922	⑬ X	⑭ X		
	R_2-Closed Down 2nd	⑦ 3.9% 1164	⑧ 1.8% 876	⑮ X	⑯ X		
S_3-Staged Firing (Top Burners Air Only)	R_1-Normal 2nd Air Reg.			⑨ 6.8% 769	3.6% 386 ⑩ 3.3% 327	8.2% 771 ㉕ 7.0% 689	4.3% 341 ㉖ 4.2% 362
	R_3-Closed* Down to 50% open			㉗ 6.6% 856	㉘ 3.1% 364	㉙ 8.0% 840	㉚ 4.5% 482
	R_2-Closed** Down to 0% open			⑲ 6.3% 1016	⑳ 2.3% 612		
S_4-Base (Top Burners Air and Coal Off)	R_1-Normal 2nd Air			㉑	㉒ 3.2% 936	6.6% 906 ㉔	5.0% 778 ㉓ 4.0% 714
	R_2-Closed Down 2nd Air						

*Secondary Air Registers: Top row of burners set at 50% open, bottom and middle registers set at 80% open.
**Top row of burners set at 15% open, bottom and middle row burners set at 80% open.

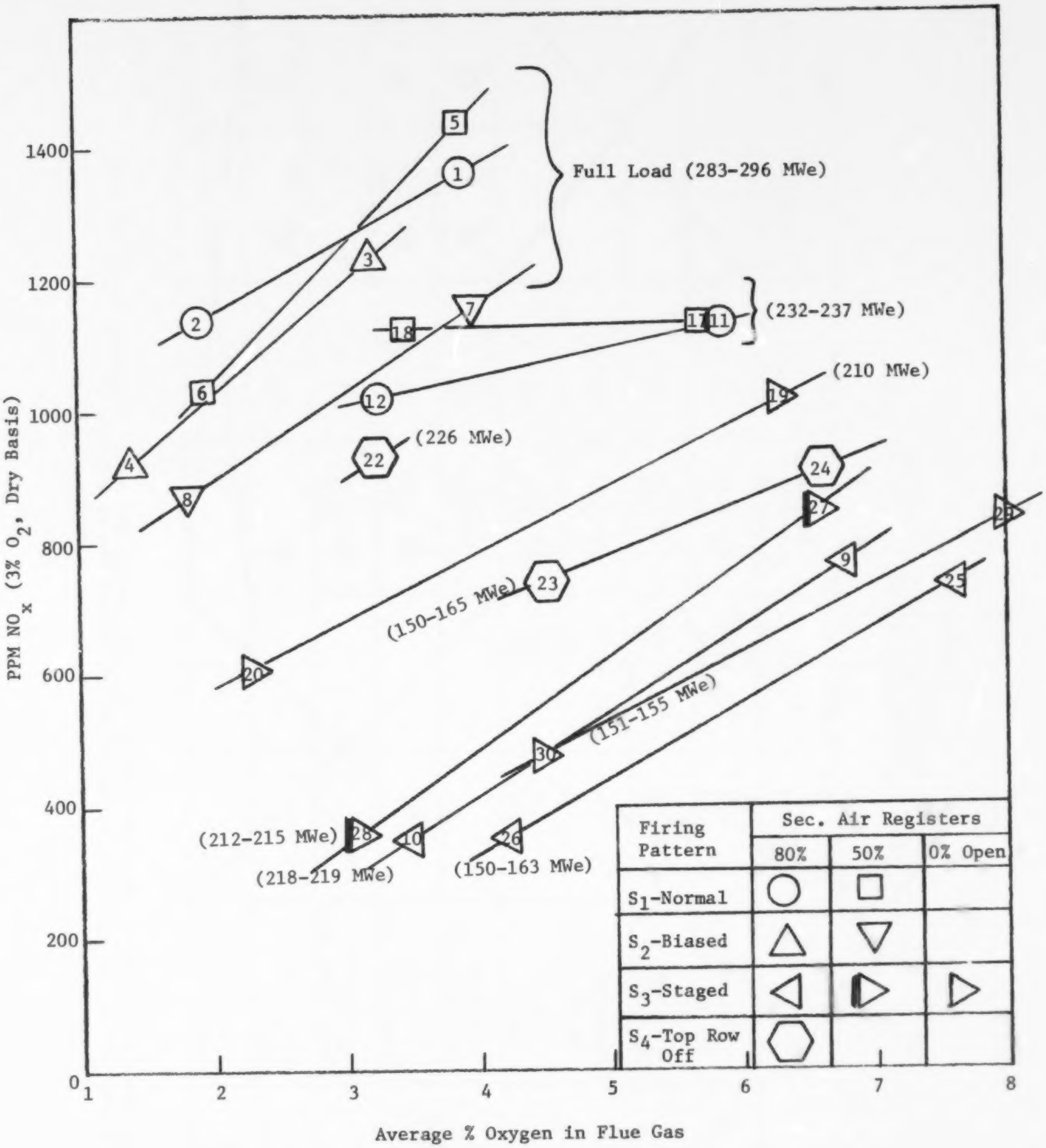

Figure 3-19. NO_x emissions vs % O_2 in flue gas on Mercer No. 1 unit.

at low loads with a wet bottom furnace. The flat furnace floor is relatively close to the bottom row of burners so that unusually high gas temperatures are maintained in the bottom of the furnace in order to maintain the slag in a molten state. Within the limited operating flexibility under full load operation, low excess air was the most important variable, reducing NO_x emissions by an average of 24%. Biased fired (top row burners fuel-lean with bottom and middle row burners fuel-rich) reduced NO_x emissions by an average of 16%. Reducing the secondary air register setting from about 80% open to about 40% to 50% open on the reheat furnace increased NO_x emission levels by about 4% under normal firing operation (S_1) and reduced NO_x emissions by an average of 8% under biased firing operation (S_2). At full load, the lowest NO_x emission levels were obtained under test run No. 8 operating conditions of biased firing, low excess air, and closed down secondary air registers. This test condition produced 876 ppm NO_x, a reduction of 36% from 809 ng/J (1383 ppm) produced under baseline operation.

Table 3-9 presents the emission results from the 12 test runs conducted at approximately 220 MWe, the maximum load achievable under staged firing (1 mill on air only) operation. Under normal firing operation (S_1), NO_x emissions were reduced by an average of 12% due to the load reduction from 290 to 220 MWe (24% reduction). Low excess air operation reduced NO_x emissions by an average of 5% under normal firing (S_1) and by 50% under staged firing (S_3). Staged firing (top row of burners on air only) was carried out with the secondary air registers of the top row of burners set at 80% open, partially closed down to 40 to 50% open, or almost completely closed down. As expected, the greatest reduction in NO_x emissions occurred when the top row secondary air registers were set at the maximum opening of about 80% open. Thus, the average reduction from the NO_x emissions for normal firing of 630 ng/J (1078 ppm NO_x) at 200 MWe were 24%, 43%, and 48% under staged firing (S_3) conditions when the secondary registers were set at 0%, 50% and 80% open, respectively. Test run No. 10 operating conditions of staged firing, low excess air and normal secondary air register settings (80% open) produced an average level of 208 ng/J (356 ppm) NO_x, or 69% below the 664 ng/J (1136 ppm) level experienced under baseline operation at about the same load.

Nine test runs were conducted at approximately 155 MWe which is the normal night-time low load conditions for this boiler. Under baseline operations at this load (top burners with air and coal off), NO_x emissions were 34% less than under full load operation. Low excess air and staged firing operation at this load again resulted in large NO_x emission reductions. Thus, low excess air combined with staged firing (test run 26 conditions) lowered NO_x emissions by 61% from baseline operation at low load.

In summary, the wet bottom furnace boiler demonstrated a high degree of NO_x emission reduction capabilities through combustion modification from the high baseline operating level of 809 ng/J (1383 ppm) at full load. Excess air level, firing pattern, and secondary air register settings were all important combustion control variables. THe optimum operations at full load (290 MWe), intermediate load (220 MWe), and low load (155 MWe) produced NO_x emission levels and percent reductions of 512 ng/J (876 ppm) or 27%, 208 ng/J (356 ppm) or 74%, and 205 ng/J (351 ppm) or 75%, respectively.

3.1.8 Morgantown Gas Turbine No. 3 (Potomac Electric Company)

Potomac Electric Company's Gas Turbine No. 3 was the first stationary power generating gas turbine tested in the current field test program. This General Electric model MS 7001 B gas turbine has a maximum continuous rating of 50 MWe and a peak output of 54 MWe. It fires No. 2 distillate oil. This unit is not equipped for water injection, so that "wet" control of gas turbine NO_x emissions could not be explored.

Flue gas samples were taken from the centers of four equal rectangular areas from each of two stacks and from the centers of each of the stacks in order that possible stratification could be measured and to obtain representative flue gas samples. Twelve to 18 measurements were recorded during the 15 to 20 minute duration of each test run.

TABLE 3-10

SUMMARY OF OPERATING AND EMISSION DATA -
MORGANTOWN STATION, GAS TURBINE NO. 3

	Operating Conditions					Flue Gas Measurements				
	Gross Load	Fuel Flow		Exhaust			NO_x Emissions (Dry Basis)			
Run No.	(MWe)	l/m	(GPM)	Temp.		% O_2	15% O_2		3% O_2	
				K	°F		ng/J	PPM	ng/J	PPM
1	10	125	33	601	621	17.9	48	82	144	247
2	25	178	47	611	640	17.3	63	108	188	322
3	48	280	74	758	905	15.2	73	125	220	376
4	54	307	81	800	980	14.7	78	133	233	398

Table 3-10 contains a summary of the major operating and emission data obtained from this test program. Figure 3-20 presents the ppm NO_x measured vs gross load (MWe), with the NO_x values adjusted to both 3% O_2 and 15% O_2 bases. As expected, the NO_x emissions increase with load, but not very sharply up to the peak load of 54 MWe.

Measured gaseous concentration stratification was very low in the stacks of this gas turbine. The reasons for this lack of stratification were the high velocity of the flue gas through the long path of ductwork (about 130 feet) in the switchback silencer and the location of the sample tubes at four diameters from the nearest upstream disturbance.

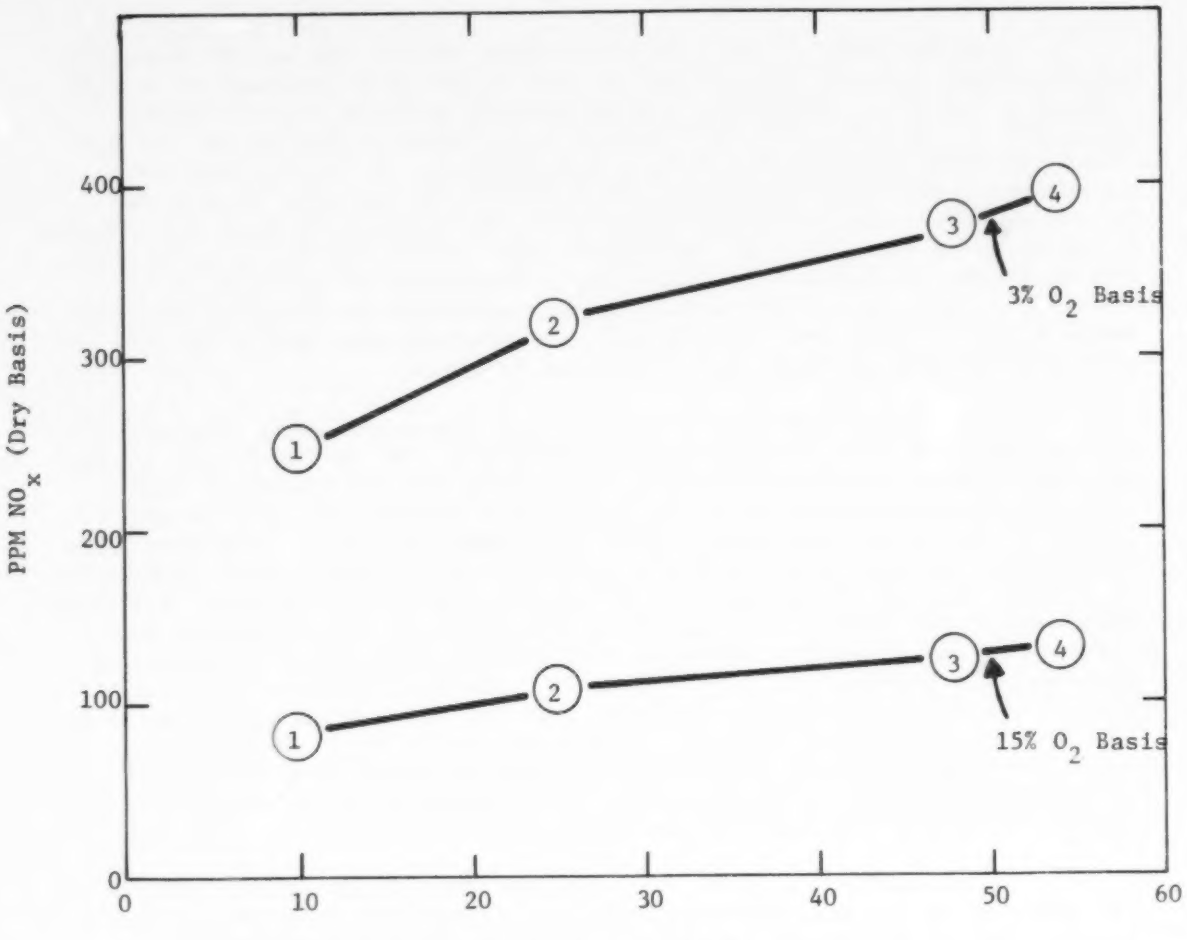

Figure 3-20. NO_x emissions vs gross load - Morgantown gas turbine No. 3.

3.2 PARTICULATE EMISSION RESULTS

As discussed in section 2.4 of this report, the use of combustion modifications to limit "NO_x" emissions may result in a tendency to increase burnout problems. Potentially, carbon burnout problems might increase particulate emissions, and the increase in unburned carbon in the fly ash could decrease precipitator collection efficiency. A further question to answer is whether particulate size distribution may also be affected by low NO_x operation of coal fired boilers, in addition to potential changes in particulate mass loading. Therefore, part of the overall program plan was to obtain sufficient data to afford a comparison of the effects of "low NO_x" firing techniques on particulate emissions by comparing measurements of particulate mass loading and size distribution, and in the fly ash with similar data obtained under baseline operation.

The particulate emission tests were conducted using sampling trains complying with EPA Method 5 requirements. The Method 5 type trains were modified to incorporate Brink, multi-stage cascade impactors for particle size determination in the heated oven between the cyclone and filter of the normal EPA train. This arrangement permitted obtaining mass loading and particle size distribution data simultaneously under isokinetic conditions with the Brink impactor located outside of the boiler. All tests were made in the boiler flue gas ducts downstream of the airheaters but upstream of any collecting devices, such as mechanical dust collectors or electrostatic precipitators. Consequently, the dust loadings are higher than at the outlet of the precipitator, but the results are not affected by the existing collection devices. Comparison of the test results taken under baseline operating conditions with data obtained under "low NO_x" operation, therefore, provides a direct determination of potential side effects of staged firing on particulates.

Particulate emissions in pulverized coal fired utility boilers are affected by the ash content of the coal fired, coal fineness, burner design, type of firing and by burnout problems (increased carbon on particulates) that may result from staged combustion and low excess firing implemented to lower NO_x emissions. Since particulate tests were conducted on each boiler with no change in pulverizer mill fineness adjustment, coal fineness does not appear to be a valid contributing factor. Carbon burnout problems, however, as evidenced by increased particulate carbon content, could be a contributor to increased particulate emissions.

In earlier ER&E field studies (2), some "side effects" attributed to "low NO_x" firing were observed based on the fact that mass loadings in some boilers tended to increase but these effects, if any, appeared to be minor. The flue gas particulate mass loading data obtained in this program are summarized in Table 3-11. Referring to Table 3-11, it appears that the emission data appear to be reliable and consistent within the accuracy of this type of testing. Comparison of emission results in the table and data on the required collection efficiency of electrostatic precipitators or other collection devices to meet the NSPS of 0.1 $lb/10^6$ BTU, for baseline vs. "low NO_x" operation in some cases shows a tendency toward increased particulate emissions with "low NO_x" firing. Data on the Salt River Project, Navajo, Boiler No. 2 (tangentially fired) and the Public Service Electric and Gas Company, Mercer, Boiler No. 1 (front wall fired) are examples. However, emissions from the boilers at the Tennessee Valley Authority, Widows Creek, Boiler No. 5 (rear wall fired), Southern Electric Generating Company, E. C. Gaston, Boiler Nos. 1 and 2 (horizontally opposed fired) and Public Service Electric Company of Colorado, Comanche, Boiler No. 1 (tangentially fired) are either the same or lower for "low NO_x" operation. It is concluded from the particulate emission data obtained in these tests, similar to the conclusion of our earlier field study (2), that any increases or decreases in dust loadings caused by "low NO_x" firing conditions do not appear to be significant.

The particulate mass loading data of Table 3-11, are plotted in Figure 3-21 as a function of unit load. It is seen that particulate emissions are not correlated with boiler size or load. The highest particulate mass loadings measured in this program were 3178 ng/J (7.39 $lbs/10^6$ BTU) on a 270 MWe boiler operating at 268 MWe. In contrast, an 800 MWe boiler produced particulate loadings of 2946 ng/J (6.85 $lbs/10^6$ BTU) at 808 MWe, and a loading of 2292 ng/J (5.33 $lbs/10^6$ BTU) was measured on a 125 MWe rated boiler operating at near full load. In the latter test (on the 125 MWe boiler), however, coal ash content was 18.27 percent compared to 9.84 and 6.62 percent, respectively, on the 270 and 800 MWe boiler tests. Mass loading emissions might also be influenced slightly by the small differences in the heating value of the fuels burned in these tests.

Another potential side effect of low NO_x operation may be an increase in carbon on fly ash or other unburned combustibles. As discussed above and in section 2.4, staging the combustion process and decreasing excess air levels produces longer, "lazier" flames with increased tendencies toward incomplete combustion. Any increase in unburned carbon as a consequence of low NO_x combustion modifications, would have a corresponding adverse effect on boiler efficiency and might tend to increase particulate loading emitted from the boiler. An assessment of the magnitude of this potential side effect may be made based on the data of Table 3-11 by comparing the percent carbon on the particulate measured under baseline and low NO_x operations, respectively. In comparing these data it may be noted that only in two cases, i.e., the Southern Electric Generating Company, E. C. Gaston, Boiler No. 1 (horizontally opposed firing) and the Public Service Electric and Gas Company, Mercer, Boiler No. 1 (front wall firing) the carbon losses are higher for low NO_x operation. In all other cases the low NO_x carbon loss data are the same or lower than for baseline operation. There is also an indication that particulate carbon content may decrease slightly under "low NO_x" firing conditions in tangentially fired boilers. This may be seen for the data for the Public Service Company of Colorado, Comanche, No. 1 and Salt River Project, Navajo, No. 2 units. These differences, however, are not statistically significant. Again, as in earlier studies (2), carbon losses in boilers fired with Western coals, i.e., Salt River Project, Navajo No. 2 and Public Service of Colorado, Camanche, No. 2 have been noted to be very low indicating the easy burnability of these coals. The effects of changes in unburned carbon resulting from low NO_x firing on boiler efficiency are discussed in section 3.4 and are shown to be minor.

Potential changes in particle size distribution that could result from low NO_x combustion modifications were also assessed in this study. Changes in size distribution of flue particulates could affect electrostatic precipitator collection efficiency. These data were obtained upstream of the electrostatic precipitators (or mechanical dust collectors) using a

TABLE 3-11

PARTICULATE EMISSION TEST RESULTS (a) PULVERIZED COAL FIRING

Utility	Date	Test No.	Firing Condition	Load, MWe	Emissions				Reqd. Efficiency to Meet 0.1 lb./10^6 BTU	% Carbon on Particulate	Coal Ash Wet, %	HHV, Wet	
					mg/m^3	Gr/SCF	ng/J	lb./10^6 BTU				cal/g	BTU/lb.
TVA, Widows Creek, Boiler No. 5	10/7/74	1B	Base	128	1.02	4.46	2288	5.32	98.12	13.04	14.64	6267	11,281
	10/8/74	1C	Base	124	1.02	4.45	2292	5.33	98.12	9.11	18.27	5699	10,258
	10/15/74	12C	Low NO$_x$	125	.87	3.80	1961	4.56	97.81	6.21	12.30	5901	10,622
	10/15/74	12D	Low NO$_x$	125	.81	3.55	1832	4.26	97.65	8.08	12.30	5901	10,622
So. Elec. Gen. Co., E. C. Gaston Boilers No. 1 & No. 2	1/22/75	28A (b)	Base	272	1.13	4.93	2657	6.18	98.38	2.69	15.00	6494	11,690
	1/22/75	28B (b)	Base	272	1.04	4.55	2451	5.70	98.25	1.09	15.00	6494	11,690
	1/23/75	29 (b)	Base	268	.87	3.80	2030	4.72	97.88	1.69	16.06	6367	11,461
	1/29/75	30 (b)	Base	270	.87	3.78	2043	4.75	97.89	2.01	13.28	6332	11,398
	1/17/75	26 (c)	Low NO$_x$	270	1.02	4.46	2356	5.48	98.18	5.65	12.12	6529	11,752
	1/20/75	27A (c)	Low NO$_x$	268	1.07	4.68	2473	5.75	98.26	3.37	9.84	6462	11,632
	1/20/75	27B (c)	Low NO$_x$	268	1.38	6.02	3178	7.39	98.65	4.08	9.84	6462	11,632
Salt River Project, Navajo Boiler No. 2	6/18/75	3C	Base	799	.73	3.17	1836	4.27	97.66	0.92	11.49	5672	10,210
	6/24/75	2A	Base	792	.80	3.48	1836	4.27	97.66	1.79	5.94	6149	11,068
	6/26/75	3D	Base	785	.44	1.93	1075	2.50	96.00	1.98	6.04	6214	11,186
	6/19/75	18B	Low NO$_x$	808	1.13	4.95	2692	6.26	98.40	0.80	11.49	5672	10,210
	6/20/75	18C	Low NO$_x$	808	1.22	5.35	2946	6.85	98.52	1.16	6.62	5989	10,780
	6/26/75	18E	Low NO$_x$	798	.54	2.36	1234	2.87	96.52	1.53	6.04	6214	11,186
Pub. Ser. Co. of Colorado, Comanche, Boiler No. 1	7/29/75	30	Base	325	.59	2.56	1337	3.11	96.79	0.66	5.36	4497	8,094
	7/30/75	33	Base	323	.59	2.59	1367	3.18	96.86	0.55	5.36	4497	8,094
	7/23/75	27A	Low NO$_x$	321	.42	1.85	972	2.26	95.58	0.46	5.43	4513	8,123
	7/23/75	27B	Low NO$_x$	321	.55	2.41	1264	2.94	96.60	0.18	5.43	4513	8,123
	8/1/75	34A	Low NO$_x$	330	.45	1.96	1006	2.34	95.73	0.50	5.62	4508	8,115
	8/1/75	34B	Low NO$_x$	330	.46	2.02	1036	2.41	95.85	0.59	5.62	4508	8,115
Pub. Ser. Elec. & Gas Co., Mercer, Boiler No. 1	1/20/76	4A	Base	265	.52	2.25	1329	3.09	96.76	2.1	9.57	7567	13,620
	1/21/76	4B	Base	268	.56	2.44	1290	3.20	96.88	1.3	9.23	7615	13,708
	1/22/76	4C	Base	269	.27	1.17	671	1.56	96.44	2.2	11.00	7323	13,181
	1/20/76	4A	Low NO$_x$	265	.57	2.47	1286	2.99	98.14	3.0	9.57	7567	13,620
	1/21/76	4B	Low NO$_x$	268	.77	3.38	1793	4.17	98.66	1.7	9.23	7615	13,708
	1/22/76	4C	Low NO$_x$	269	.26	1.12	606	1.41	95.69	5.8	11.00	7323	13,181

(a) Sampling at air heater outlet upstream of collection devices.

(b) Boiler No. 2.

(c) Boiler No. 1.

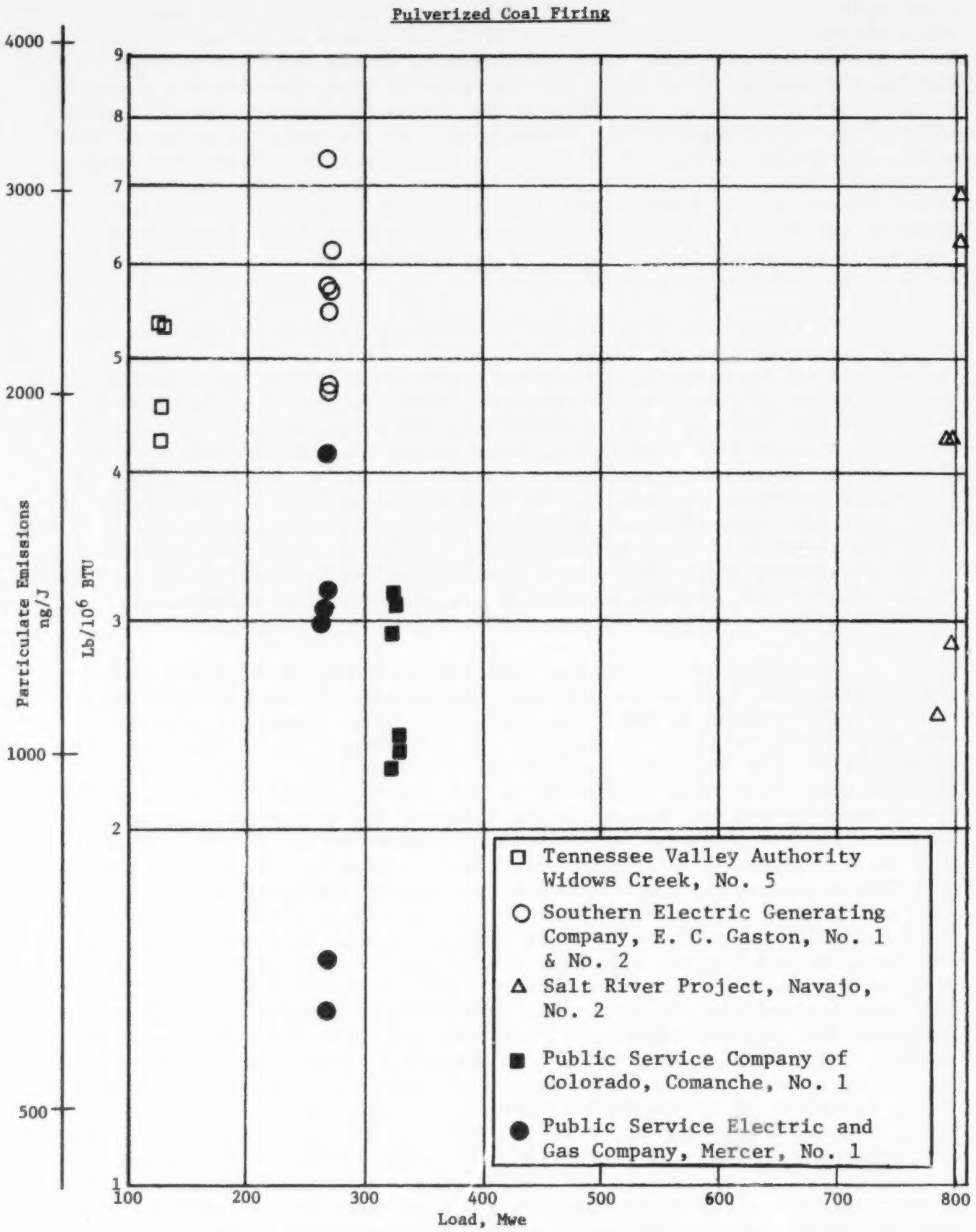

Figure 3-21. Particulate emissions from utility boilers.

Brink multi-stage cascade impactor incorporated in an EPA type sampling train between the cyclone and the filter as discussed above and in section 2.4. A separate pump and flow rate measuring device was used to pull samples through the Brink impactor for particle size distribution measurements. This arrangement permitted simultaneous sampling for mass loading and particle size distribution determination at the required rates in isokinetic traverses of the boiler flue gas ducts, with the Brink equipment located outside of the boiler. Thus, the proper recommended flow rates were obtained in the Brink impactor to obtain the specified aerodynamic diameter cut points. The Brink impactor consists of five stages, each having cut points at rated conditions at diameters of 2.5, 1.5, 1.0, 0.5 and 0.25 μm followed by a final filter.

Particle size distribution measurement results obtained in this program are summarized in Tables 3-12, 3-13, 3-14 and 3-15. The data include all of the material collected in the probe and the cyclone for the size range greater than 2.5 microns. Comparing the data in Tables 3-13, 3-14 and 3-15, it is seen that there are no significant differences in particle size distribution between low NO_x and baseline operation for the three boilers tested. The data in Table 3-12 however, show major increases for the smaller size fractions with low NO_x firing that could adversely affect precipitator collection efficiency. The significance of the latter data, however, is open to question, first, due to the relatively small size of the sample obtained in these tests in the Brink impactor and, second, because of the problems with leaks in the sampling equipment during this particular set of measurements.

The sampling arrangement used for obtaining particulate particle size distribution information employed the cyclone of the EPA train as the first cut point ahead of the Brink impactor. It is generally accepted that this device collects all material greater than 7 μm in diameter. The fractionation size (D_{50}) for each of the Brink impactor stages is the particle size (aerodynamic diameter in μm) collected with 50% efficiency by the impactor stage. For the Brink impactor the aerodynamic diameter (D_{50}) for each stage is as noted above when operated at the prescribed flow rates. Figures 3-22, 3-23, 3-24 and 3-25 present the size distribution data vs aerodynamic diameter for each boiler tested as a function of solids loading in cumulative percent below the stated size. It should be noted that all the measurements were made at or near full boiler load under both baseline and low NO_x operating conditions. Referring to the results shown in Figures 3-23 and 3-24, data plotted exhibit consistent trends for both baseline and low NO_x operations indicating no adverse side effects resulting from low NO_x firing modifications for these two boilers firing Western coal. On the other hand, some scatter is indicated in Figure 3-25 for the lower size fractions in tests conducted on the wet bottom furnace firing Eastern coal at the Public Service Electric and Gas Company's Mercer Station Boiler No. 1. However, there is no indication of detrimental side effects due to low NO_x operation. The data in Figure 3-22 cannot be reconciled with those in Figures 3-23, 3-24 and 3-25 which is not surprising in view of the small samples obtained and some leaks in the sampling equipment experienced during the tests on the Southern Electric Generating Company's boilers.

TABLE 3-12

PARTICLE SIZE DISTRIBUTION, WT.%

E. C. GASTON BOILER NOS. 1 & 2
SOUTHERN ELECTRIC GENERATING COMPANY

Size Range	Base - Boiler No. 2			Low NO_x - Boiler No. 1		
	29	30	Avg.	34	37	Avg.
>2.5μ*	93.67	91.44	92.6	59.50	59.23	59.4
2.5μ	2.53	2.65	2.6	11.74	9.79	10.8
1.5μ	0.63	0.60	0.6	4.05	4.10	4.0
1.0μ	0.89	1.03	1.0	5.67	6.10	5.9
0.5μ	1.26	1.63	1.4	8.91	10.19	9.5
<0.5μ	1.02	2.65	1.8	10.12	10.60	10.4

* Includes probe and cyclone

TABLE 3-13

PARTICLE SIZE DISTRIBUTION, WT.%

SALT RIVER PROJECT BOILER NO. 2
NAVAJO STATION - PAGE, ARIZONA

	Baseline Firing				Low NO_x Firing			
Size Range	2A (Box 1)	2A (Box 2)	3D	Avg.	18C (Box 1)	18C (Box 2)	18E	Avg.
>2.5μ*	95.80	92.17	90.29	92.7	95.75	93.47	92.61	93.9
2.5μ	1.18	2.97	4.76	3.0	0.83	1.96	2.88	1.9
1.5μ	0.42	0.71	0.97	0.7	0.36	0.52	0.89	0.6
1.0μ	0.67	1.02	1.23	1.0	0.68	0.72	1.18	0.9
0.5μ	1.03	1.49	1.12	1.2	1.15	1.24	0.92	1.1
<0.5μ	0.90	1.64	1.60	1.4	1.23	2.09	1.52	1.6

* Includes probe and cyclone.

TABLE 3-14

PARTICLE SIZE DISTRIBUTION, WT. %

COMANCHE BOILER NO. 1
PUBLIC SERVICE COMPANY OF COLORADO

	Normal Firing			Low NO_x Firing				
Size Range	30	33	Avg.	27A	27B	34	35	Avg.
>2.5μ*	82.18	81.38	81.8	77.4	83.84	82.41	79.29	80.7
2.5μ	8.73	9.5	8.9	11.31	9.53	7.04	7.76	8.9
1.5μ	1.96	2.05	2.0	2.71	1.62	2.29	2.48	2.3
1.0μ	2.49	2.79	2.6	3.17	1.86	2.9	3.73	2.9
0.5μ	2.94	2.89	2.9	2.94	2.1	3.52	4.45	3.3
<0.5μ	1.70	1.39	1.6	2.49	1.05	1.85	2.13	1.9

* Includes probe and cyclone.

TABLE 3-15

PARTICLE SIZE DISTRIBUTION, WT. %

MERCER STATION BOILER NO. 1
PUBLIC SERVICE ELECTRIC AND GAS COMPANY

	Base				Low NO_x			
	Furnace No. 12				Furnace No. 11			
Size Range	4A	4B	4C	Avg.	4A	4B	4C	Avg.
>2.5μ*	84.8	88.3	81.9	85.0	88.6	90.7	80.0	86.4
2.5μ	2.7	4.9	2.9	3.5	3.2	2.9	9.7	5.3
1.5μ	2.9	2.4	1.5	2.3	2.2	0.5	2.7	1.8
1.0μ	3.8	2.0	0.9	2.2	1.3	2.2	2.4	2.0
0.5μ	1.9	1.5	0.1	1.2	2.2	1.0	0.6	1.2
<0.5μ	3.9	0.9	12.7	5.8	2.5	2.7	4.6	3.3

* Includes probe and cyclone.

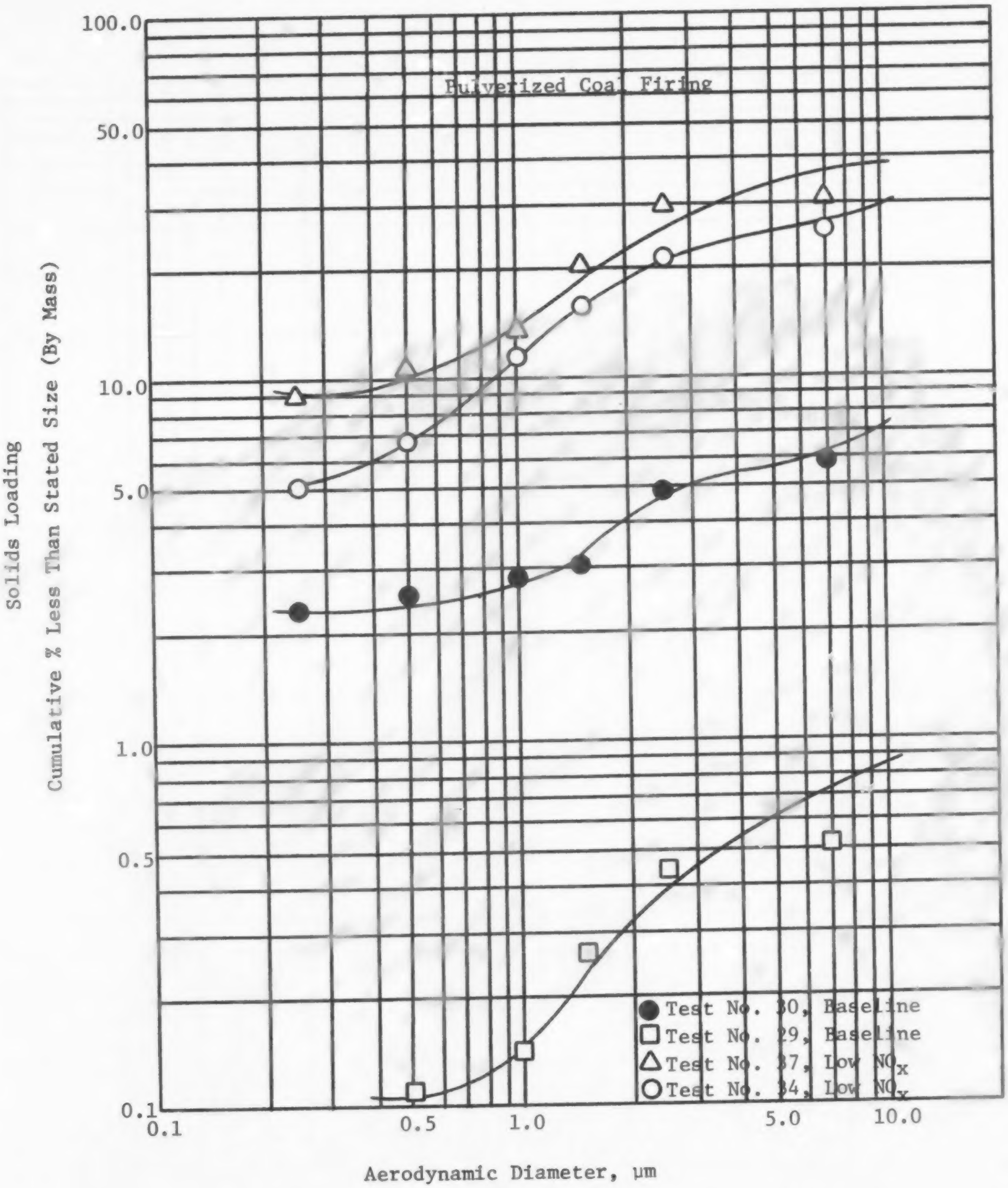

Figure 3-22. Particle size distribution, Southern Electric Generating Company, E. C. Gaston, boilers No. 1 and No. 2.

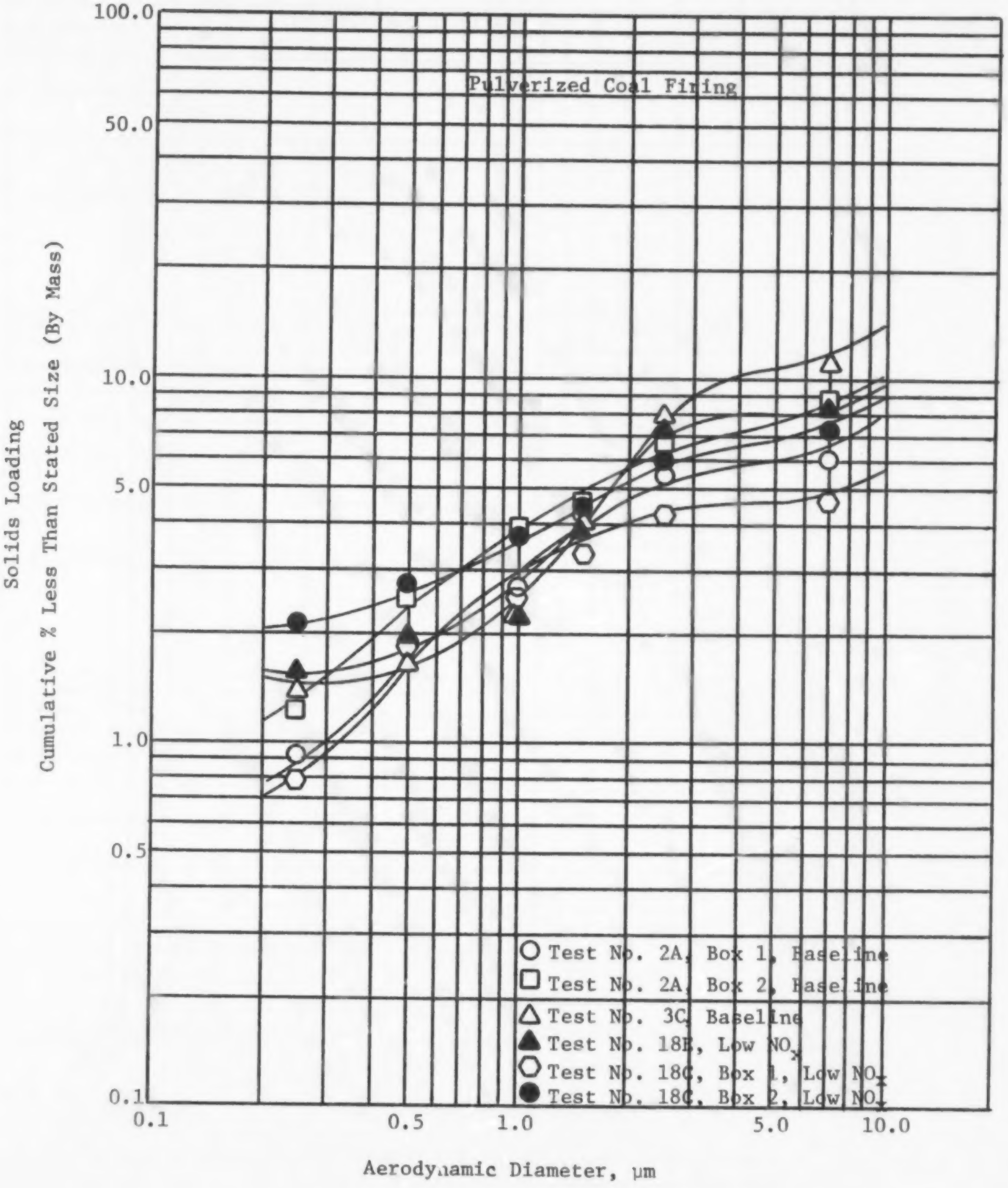

Figure 3-23. Particle size distribution, Salt River project, Navajo station, boiler No. 2.

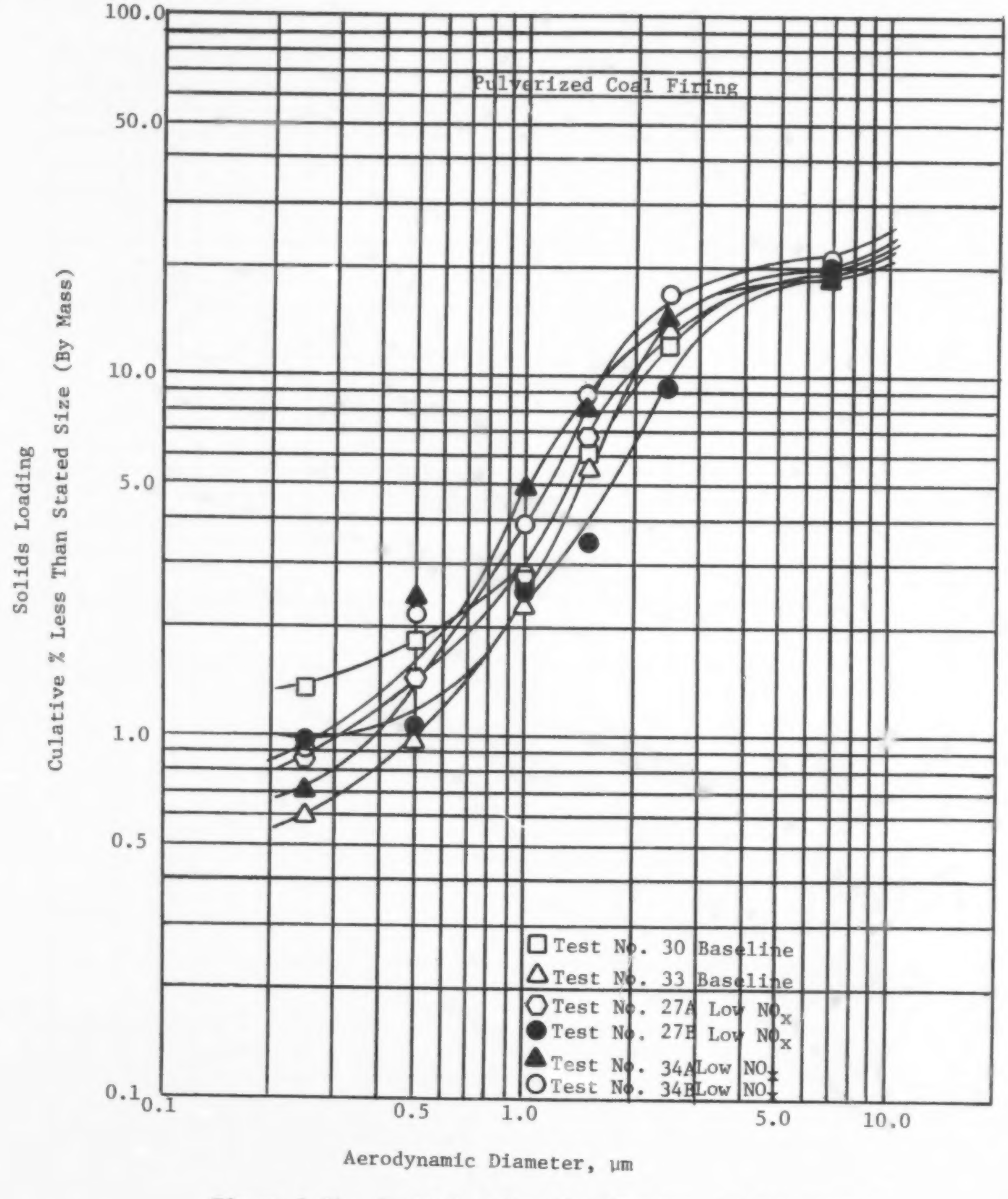

Figure 3-24. Particle size distribution, Public Service Company of Colorado, Comanche station, boiler No. 1.

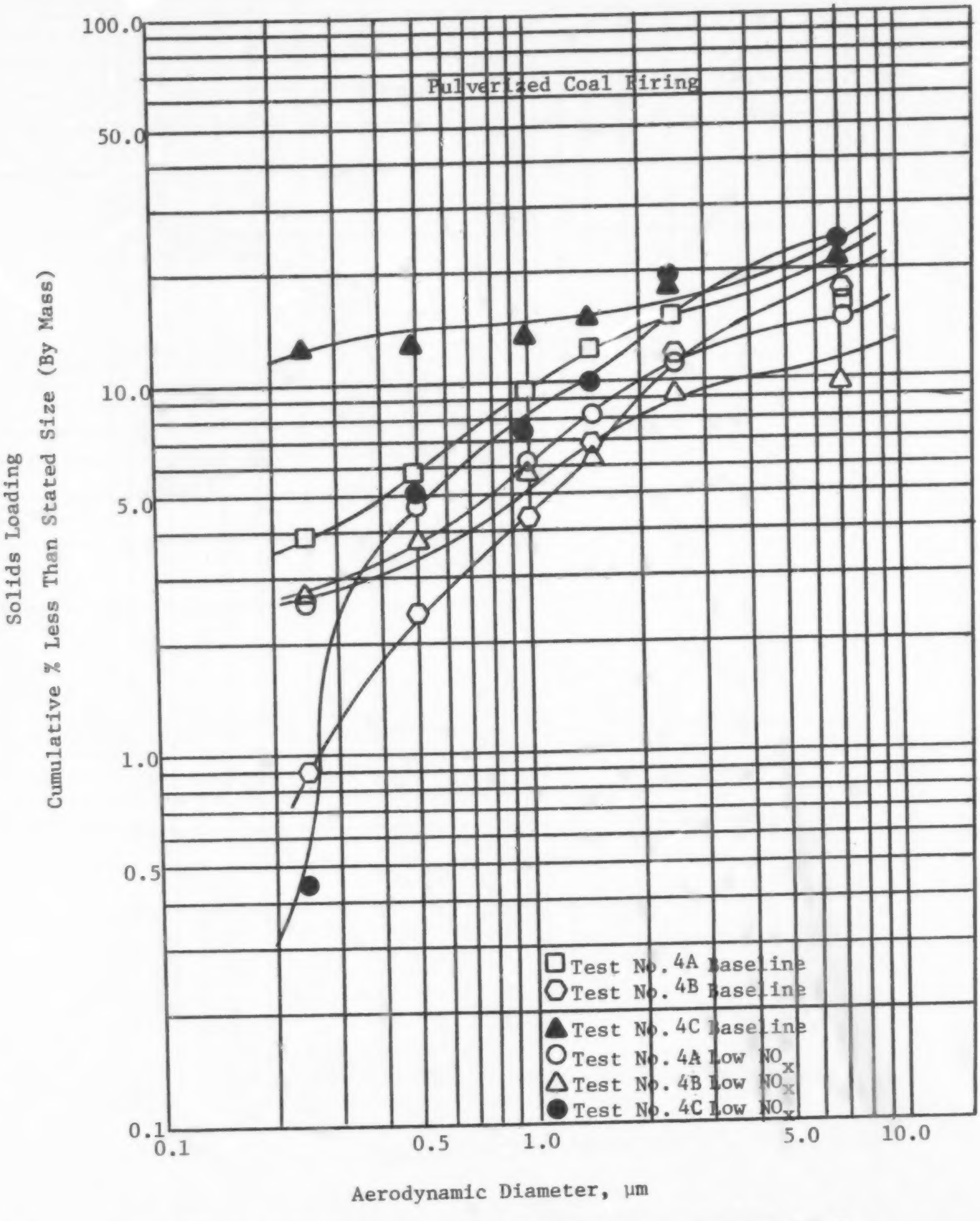

Figure 3-25. Particle size distribution, Public Service Electric and Gas Co., Mercer station, boiler No. 1.

3.3 FURNACE WATERWALL CORROSION PROBING

In the current program, significant changes were made in the conditions for measuring corrosion rates by exposed coupons in order to better relate rates obtained on corrosion probes to actual furnace wall tube corrosion rates. In prior ER&E studies (2), coupon corrosion rates obtained in 300-hour tests averaged approximately 50 mils per year with considerable scatter between high and low values. These high rates were the result of the higher than normal exposure temperature of 742 K (875°F) and the mild acid pickling of the coupons prior to exposure which resulted in high initial corrosion rates. In the present program, coupon temperatures were controlled at temperatures approximating those of the furnace wall tubes, 603-658 K, (625-725°F) and the acid pickling procedure was eliminated. As a result, the corrosion rates measured were generally lower and more consistent for each boiler than the previous data. Other test conditions were kept the same as in the previous program, i.e., probes were inserted through openings in the furnace wall as close as possible to vulnerable furnace areas and the exposure was maintained at approximately 300 hours. The analytical procedures used were also the same in both programs. Thus, each coupon was visually inspected after exposure and was photographed to record its appearance. Scale was then removed from the outside diameter surfaces by dry honing with glass beads under low pressure. The coupon was then weighed to obtain the weight loss from the outside surface. This was followed by dry honing of the inside diameter surface scale after which the coupon was reweighed to determine the weight loss from the inside surfaces. Corrosion rates were then calculated as the loss in mils per year (m/yr) using the weight loss data, the combined exposed coupon areas, the metal and scale densities, and the exposure time.

Coupon corrosion rates were determined for 60 coupons mounted on 20 probes (3 coupons/probe) exposed in 8 boilers firing pulverized coal. The data obtained are tabulated in Tables 3-16, 3-17, 3-18, 3-19 and 3-20. Referring to the tables, it may be seen that the corrosion rates obtained are quite consistent, ranging from values of 6 mils/year to around 40 mils/year and averaging about 19 mils/year (excluding the data in Table 3-18 and for probe No. 3 in Table 3-19 for reasons that will be discussed later). These rates are considerably lower than the 50 mils/year average obtained in our previous study under accelerated conditions. The lower and more consistent coupon corrosion rates measured in this program reflect the changes made in test procedures to more closely approximate actual furnace wall tube conditions. However, these rates are still an order of magnitude greater than the 1 to 3 mils per year corrosion rates that are expected for the wastage of actual furnace waterwall tubes under normal firing conditions. Therefore, the corrosion probing results should be still viewed as only the relative measure of corrosion tendency under baseline and low NO_x firing conditions.

Referring to Table 3-18, it is seen that the coupons on probes No. 1 and No. 3 had undergone higher corrosion rates than those on probes No. 2 and No. 4, respectively. The higher rates are due to some of the metal having been inadvertently removed in disassembling the coupons caused by galling of the threads between coupons. The indicated rates of corrosion on probes No.

TABLE 3-16

CORROSION RATE DATA

WIDOWS CREEK STATION

BOILERS NO. 5 AND NO. 6

TENNESSEE VALLEY AUTHORITY

Boiler	Probe No. (a)	Firing Condition	Coupon Corrosion Rate, Mils/Year	Average
Boiler No. 6 (North Side)	4	Base	14.6 12.0 10.2 (b)	12.3
Boiler No. 6 (South Side)	3	Base	11.1 11.6 9.7 (b)	10.8
Boiler No. 5 (North Side)	2	Low NO_x	18.8 13.4 12.5 (b)	14.9
Boiler No. 5 (South Side)	1	Low NO_x	15.1 13.4 11.7 (b)	13.4

(a) Probes located between A B burners, top & next to top rows, respectively.

(b) Coupons farthest into furnace.

TABLE 3-17

CORROSION RATE DATA

E. C. GASTON STATION

SOUTHERN ELECTRIC GENERATING COMPANY, WILSONVILLE, ALABAMA

Boiler (a)	Probe No.	Firing Condition	Coupon Corrosion Rate, Mils/Year	Average
Boiler No. 2 @ (IR No. 1)	3	Base	10.3 7.3 10.2 (b)	9.3
Boiler No. 2 @ (IR No. 10)	4	Base	8.0 6.3 6.0 (b)	6.8
Boiler No. 1 @ (IR No. 10)	2	Low NO_x	20.0 12.3 10.4 (b)	14.2
Boiler No. 1 @ (IR No. 1)	1	Low NO_x	11.4 7.1 10.1 (b)	9.5

(a) Probes inserted through slag blower ports in side walls about 8 feet above top burners and 12 feet from rear furnace corner.

(b) Coupons farthest into furnace.

TABLE 3-18
CORROSION RATE DATA
NAVAJO STATION
SALT RIVER PROJECT, PAGE, ARIZONA

Boiler (a)	Probe No.	Firing Condition	Coupon Corrosion Rate, Mils/Year	Average
No. 1 (North Side)	1 (b)	Base	62.8 32.0 21.3 (c)	38.7
No. 1 (South Side)	2	Base	15.1 10.6 13.2 (c)	13.0
No. 2 (North Side)	3 (b)	Low NO_x	43.8 29.2 19.7 (c)	30.9
No. 2 (South Side)	4	Low NO_x	16.2 15.1 15.5 (c)	15.6

(a) Probes inserted through observation doors in side walls between B & C burner rows.

(b) Probes with damaged coupons.

(c) Coupons farthest into furnace.

TABLE 3-19

PUBLIC SERVICE COMPANY OF COLORADO
COMANCHE STATION - BOILER NO. 1

CORROSION RATE DATA

Probe No.	Location (a)	Firing Cond.	Coupon Corrosion Rate, Mils/Yr.	Average
3 (b)	S.E. Corner Between B&C Burners	Base	81.9 49.1 15.8 (c)	48.9
4	N.W. Corner Between B&C Burners	Base	34.0 24.0 23.4 (c)	27.1
1	S.E. Corner Between B&C Burners	Low NO_x	41.6 25.6 15.6 (c)	27.6
2	N.W. Corner Between B&C Burners	Low NO_x	15.5 13.5 96.2 (c)	41.7

(a) 5th floor elevation.

(b) Probe with damaged coupons.

(c) Coupons farthest into furnace.

TABLE 3-20

CORROSION RATE DATA

MERCER STATION

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Boiler/Furnace	Location	Probe No.	Firing Cond.	Coupon Corrosion Rate, Mils/Yr.	Average
Boiler No. 2 (Furnace No. 1)	Elev No. 3 Between Furnaces	3	Base	10.1 73.1 117.3 (a)	66.8
Boiler No. 2 (Furnace No. 2)	South Wall, Elev No. 3	4	Base	6.1 9.7 38.2 (a)	17.3
Boiler No. 1 (Furnace No. 1)	South Wall, Elev No. 3	1	Low NO_x	5.2 17.1 163.2 (a)	61.8
Boiler No. 1 (Furnace No. 1)	Elev No. 3 Between Furnaces	2	Low NO_x	12.4 41.9 123.4 (a)	59.2

(a) Coupons farthest into furnace.

1 and No. 3, therefore, are not reliable. Comparing the data from probes No. 2 and No. 4 with the results in Tables 3-16 and 3-17, it may be seen that corrosion rates tend to vary between 10-15 mils/year with the maximum at about 20 mils/year. Also, although these results suggest somewhat higher corrosion rates for the probes exposed under low NO_x conditions, the magnitude of the increase is relatively minor.

The validity of the corrosion rates determined for probe No. 3 in Table 3-19 is also suspect due to inadvertent metal removal caused by thread damage. The results from the remaining probes, however, appear to be quite reliable even though they are higher than for the other tests. Comparing the corrosion rates for probes No. 1 and No. 2 to those for probe No. 4, there is a suggestion of a lower rate of corrosion under "low NO_x" firing conditions. However, within the accuracy of corrosion rate measurements with probe coupons, it appears that the effect of "low NO_x" is minor.

The corrosion rates measured on the Mercer Station boilers of the Public Service Electric and Gas Company, as shown in Table 3-20, are quite different from those determined in the other tests. Due to the close spacing of the furnace tubes and the construction of the access doors in which the probes were mounted on the furnace, extensions were required on the probes to hold the coupons. Three "dummy" coupons were inserted between the probe proper and the coupons exposed for test (6 coupons in series). As indicated by the high apparent corrosion rates measured, the extensions evidently affected the air cooling available for the exposed coupons. This is supported by the fact that the highest rates were measured for each probe for the coupon inserted furthest into the furnace, with successively lower rates measured for the adjacent coupons closer to the furnace walls. Using the coupon rates measured only for the coupons inserted closer to the tube walls, no significant difference can be detected between the values obtained for baseline and low NO_x firing conditions, respectively.

Directionally it appears that under some conditions "low NO_x" firing conditions may result in somewhat higher corrosion rates based on the results of coupon corrosion probe measurements. Thus, although the conclusion of the corrosion probing results is that no major differences in corrosion can be observed for coupons exposed under low NO_x operating conditions compared to those subjected to baseline boiler operating conditions, only long term corrosion measurements of actual furnace tube wastage can answer the question of the magnitude of corrosion rate increase caused by staged firing of boilers with coal. The corrosion probing data obtained so far provides confidence that catastrophic corrosion problems will not occur as a result of stage firing of coal, and therefore, long term corrosion testing under low NO_x conditions is a reasonable approach. It is planned that further detailed corrosion probing results will be correlated with actual tube wastage measurements obtained in long term corrosion tests.

3.4 EFFECT OF COMBUSTION MODIFICATIONS ON BOILER PERFORMANCE

Prior field study results (2) indicated a tendency for particulate carbon content to increase under low NO_x operating conditions, especially for wall fired boilers. Potentially, an increase in unburned carbon should result in lower boiler efficiency but this adverse side effect did not materialize in the previous study because of the offsetting effect of lower excess air operation under low NO_x operating conditions. In the present study the effect of modified combustion operation on boiler performance was investigated and evaluated for each boiler tested where particulate data were obtained under baseline and optimum "low NO_x" conditions. Control room board data and other pertinent information representative of each test run were recorded and boiler efficiency was calculated using the heat loss method (ASME Steam Generating Units, Power Test Codes, Abbreviated Efficiency Test). Calculations were based on the assumption that fly ash and bottom ash combustible content were the same and unmeasured losses were 0.5 percent. An example of typical performance data and the calculations made are shown in ASME test forms in Tables 3-21 and 3-22.

Table 3-23 lists boiler efficiencies calculated for each boiler tested along with other pertinent boiler performance information. Differences in calculated boiler efficiencies between baseline and low NO_x test conditions provide a comparison of any efficiency debit or credit accruing to low NO_x operating conditions. Boiler efficiency, in general, increases with load and decreases with increasing coal ash or unburned combustible content of the particulates.

It can be seen from the data in Table 3-23 that low NO_x modified combustion operation does not decrease boiler efficiency significantly. In fact, some apparent increases are calculated in some cases. For example, the Tennessee Valley Authority, Boiler No. 5, the Salt River Project, Boiler No. 2, and the Public Service Company of Colorado, Boiler No. 1, test data show small increases in efficiency under low NO_x firing conditions due to decreases in uncombustible losses, lower coal ash, and excess air levels. Differences in boiler efficiency are also inconsequential with low NO_x operation where carbon losses increased substantially, as in the case of the Southern Electric Company, Boilers No. 1 and No. 2. Here the efficiency debits due to increases in unburned carbon for the low NO_x tests are offset by the increases in efficiency resulting from operation at lower excess air and the lower ash content of the coal burned during the low NO_x tests. In general, staging the combustion operation and reducing excess air levels for a boiler to reduce NO_x emissions tends to increase somewhat the unburned combustibles. However, the debit in efficiency resulting from such incomplete utilization of the fuel is offset by the improved efficiency resulting from lower excess air operation. Therefore, the conclusion reached based on these results is that "low NO_x" firing, as used in this study, had no major effect on boiler efficiency.

TABLE 3-21

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

SUMMARY SHEET

PTC 4.1-a (1964)

TEST NO. 1A BOILER NO. 6 DATE 4-18-72
OWNER OF PLANT TVA LOCATION Widows Creek
TEST CONDUCTED BY Esso Research & Engineering Co. OBJECTIVE OF TEST Boiler Performance DURATION 4 Hrs.
BOILER, MAKE & TYPE B&W Radiant RATED CAPACITY 125 MW
STOKER, TYPE & SIZE
PULVERIZER, TYPE & SIZE Type E BURNER, TYPE & SIZE
FUEL USED Bituminous Coal MINE COUNTY STATE SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	
6	STEAM TEMPERATURE AT R.H. INLET	F	
7	STEAM TEMPERATURE AT R.H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON.) (BOILER)	F	
9	STEAM QUALITY % MOISTURE OR P. P. M.		
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	
11	TEMP. AIR FOR COMBUSTION (This is Reference Temperature) †	F	88
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	372
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	
21	HEAT ABS/LB R. H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	15.87
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	912.1
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	0.66
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	11.6

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{(\text{Item 28} \times \text{Item 41})}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{(\text{Item 26} \times \text{Item 20}) + (\text{Item 27} \times \text{Item 21})}{1000} + \text{Item 30}$	kB/hr	

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	14.4
33	O_2	% VOL	3.3
34	CO	% VOL	0.04
35	N_2 (BY DIFFERENCE)	% VOL	82.26
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt		OIL	
37	MOISTURE	5.4	51	FLASH POINT F*	
38	VOL MATTER		52	Sp. Gravity Deg. API*	
39	FIXED CARBON		53	VISCOSITY AT SSU* BURNER SSF	
40	ASH		44	TOTAL HYDROGEN % wt	
	TOTAL		41	Btu per lb	
41	Btu per lb AS FIRED	11452			
42	ASH SOFT TEMP.* ASTM METHOD			GAS	% VOL

	COAL OR OIL AS FIRED ULTIMATE ANALYSIS				
			54	CO	
43	CARBON	67.27	55	CH_4 METHANE	
44	HYDROGEN	4.29	56	C_2H_2 ACETYLENE	
45	OXYGEN		57	C_2H_4 ETHYLENE	
46	NITROGEN		58	C_2H_6 ETHANE	
47	SULPHUR	0.77	59	H_2S	
40	ASH	15.87	60	CO_2	
37	MOISTURE		61	H_2 HYDROGEN	
	TOTAL			TOTAL	

	COAL PULVERIZATION				
				TOTAL HYDROGEN % wt	
48	GRINDABILITY INDEX*	-	62	DENSITY 68 F ATM. PRESS.	
49	FINENESS % THRU 50 M*		63	Btu PER CU FT	
50	FINENESS % THRU 200 M*		41	Btu PER LB	

64 INPUT-OUTPUT EFFICIENCY OF UNIT % $\frac{\text{ITEM 31} \times 100}{\text{ITEM 29}}$

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		6.90
66	HEAT LOSS DUE TO MOISTURE IN FUEL		0.55
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		3.95
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		1.26
69	HEAT LOSS DUE TO RADIATION		0.002
70	UNMEASURED LOSSES		0.5
71	TOTAL		13.16
72	EFFICIENCY = (100 – Item 71)		86.84

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

TABLE 3-22

PTC 4.1-b (1964)

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

CALCULATION SHEET

Revised September, 1965

OWNER OF PLANT TVA TEST NO. 1A BOILER NO. 6 DATE 4-18-72

30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\dfrac{\text{ITEM 15} \;\ldots\; - \;\ldots\; \text{ITEM 17}}{1000}\right]$ = ... kB/hr
24	*If impractical to weigh refuse, this item can be estimated as follows* DRY REFUSE PER LB OF AS FIRED FUEL = $\dfrac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$ CARBON BURNED PER LB AS FIRED FUEL = $\dfrac{\overset{\text{ITEM 43}}{67.27}}{100} - \left[\dfrac{\overset{\text{ITEM 22}}{0.1587} \times \overset{\text{ITEM 23}}{912.1}}{14{,}500}\right] = 0.66$ NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.
25	DRY GAS PER LB AS FIRED FUEL BURNED = $\dfrac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ × (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S) $= \dfrac{11 \times \overset{\text{ITEM 32}}{14.4} + 8 \times \overset{\text{ITEM 33}}{3.3} + 7\left(\overset{\text{ITEM 35}}{82.26} + \overset{\text{ITEM 34}}{0.04}\right)}{3 \times \left(\overset{\text{ITEM 32}}{14.4} + \overset{\text{ITEM 34}}{0.04}\right)} \times \left[\overset{\text{ITEM 24}}{0.66} + \dfrac{\overset{\text{ITEM 47}}{0.77}}{267}\right] = 11.6$
36	EXCESS AIR† = $100 \times \dfrac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \dfrac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = ...

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}}$ × 100 =	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × (t_{lvg} – t_{air}) Unit = $\overset{\text{ITEM 25}}{11.6} \times 0.24\ \overset{\text{(ITEM 13) – (ITEM 11)}}{372 - 88} = 790$	790	$\frac{65}{41}$ × 100 =	6.90
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) – (ENTHALPY OF LIQUID AT T AIR)] = $\dfrac{\overset{5.4}{\text{ITEM 37}}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) 1227.9 – (ENTHALPY OF LIQUID AT T ITEM 11) 56] = 63.3	63.3	$\frac{66}{41}$ × 100 =	0.55
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) – (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\dfrac{\overset{4.29}{\text{ITEM 44}}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) 1227.9 – (ENTHALPY OF LIQUID AT T ITEM 11) 56] = 452.5	452.5	$\frac{67}{41}$ × 100 =	3.95
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = $\overset{\text{ITEM 22}}{0.1587} \times \overset{\text{ITEM 23}}{912.1} = 144.8$	144.8	$\frac{68}{41}$ × 100 =	1.26
69	HEAT LOSS DUE TO RADIATION* = $\dfrac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL — ITEM 28} \ldots}$	0.2	$\frac{69}{41}$ × 100 =	0.002
70	UNMEASURED LOSSES **	......	$\frac{70}{41}$ × 100 =	0.5
71	TOTAL	......	......	13.16
72	EFFICIENCY = (100 – ITEM 71)	......	......	86.84

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† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

TABLE 3-23

SUMMARY OF BOILER PERFORMANCE CALCULATIONS

Company, Station	Boiler No.	Firing Mode	Test No.	Load, MWe	% O_2	NO_x Emissions at 3% O_2 PPM	NO_x Emissions at 3% O_2 lb./10^6 BTU	NO_x Emissions at 3% O_2 ng/J	Coal Ash, % (Wet Basis)	% Carbon on Particulate	Boiler Efficiency, %
Tenn. Valley Authority, Widows Creek Station	5	Base	1B	128	2.4	409	.56	239	14.64	13.0	86.6
		Base	1C	124	2.5	441	.60	258	18.27	9.1	86.2
	5	Low NO_x	12C	125	2.5	412	.56	241	12.30	6.2	87.7
		Low NO_x	12D	125	2.5	412	.56	241	12.30	8.1	87.3
So. Electric Generating Company, E. C. Gaston Station	2	Base	28A	272	4.2	584	.79	341	15.00	2.7	89.8
		Base	28B	272	4.2	584	.79	341	15.00	1.1	90.1
		Base	29	268	4.1	572	.78	335	16.06	1.7	89.9
		Base	30	270	4.3	606	.82	354	13.28	2.1	89.2
	1	Low NO_x	26	270	3.9	349	.47	204	12.12	5.7	89.2
		Low NO_x	27A	268	3.9	316	.43	185	9.84	3.4	89.6
		Low NO_x	27B	268	3.9	316	.43	185	9.84	4.1	89.8
Salt River Project, Navajo Station	2	Base	3B	799	4.8	492	.67	288	11.49	0.9	89.0
		Base	2A	792	3.9	332	.45	194	5.94	1.8	89.6
		Base	3D	785	4.8	346	.47	202	6.04	2.0	89.6
	2	Low NO_x	18B	808	4.4	349	.47	204	11.49	0.8	89.2
		Low NO_x	18C	808	4.6	346	.47	202	6.62	1.2	89.5
		Low NO_x	18E	798	3.7	280	.38	163	6.04	1.5	89.7
Pub. Ser. Co. of Colorado, Comanche Station	1	Base	30	325	3.7	380	.52	222	5.36	.66	80.8
		Base	33	323	3.9	389	.53	227	5.36	.55	80.2
		Low NO_x	27A	321	3.9	246	.33	144	5.43	.46	80.7
		Low NO_x	27B	321	3.9	246	.33	144	5.43	.18	80.7
		Low NO_x	34	330	3.4	205	.28	120	5.62	.50	80.3
		Low NO_x	35	330	3.4	205	.28	120	5.62	.59	80.3
Pub. Ser. E&G Co., Mercer Station	1	Base	2	265	3.8	1095	1.49	640	9.57	2.1	90.0
		Base	4	268	3.1	1175	1.60	687	9.23	1.3	90.4
		Base	6	269	3.3	1070	1.46	626	11.00	2.2	90.1
		Low NO_x	1	265	1.5	940	1.28	550	9.57	3.0	90.1
		Low NO_x	3	268	1.9	827	1.12	484	9.23	1.7	90.3
		Low NO_x	5	269	2.2	924	1.26	540	11.00	5.8	89.8

3.5 SUMMARY OF SULFUR OXIDES MEASUREMENTS

Flue gas samples for sulfur oxides (SO_2 and SO_3) determination were taken from the boiler ducts at the same location as the samples extracted for continuous analysis by the instrumental train of the ER&E analytical van discussed in section 2.7. Normally this location is at the boiler outlet downstream of the economizer but upstream of the regenerative airheaters. Wet chemical SO_2/SO_3 determinations followed procedures outlined in section 2.7.

Tables 3-24, 3-25, 3-26, 3-27 and 3-28 summarize the results of sulfur oxides measurements made in this program. Sulfur oxides emission concentrations calculated on the assumption of 100 percent conversion of the sulfur content of the fuels burned during the test period, given in the tables, can be compared with the separately determined values of SO_2 and SO_3. It can be seen that calculated SO_x values are higher than measured sulfur oxides concentrations. This is not unexpected for pulverized coal fired boilers. In dry bottom pulverized coal fired boiler installations, about 15 to 20 percent of the ash is extracted as bottom ash and 80 to 85 percent is carried with the flue gases to electrostatic precipitators (or other collection devices) which collect up to 98/99+ percent of the flyash. Another portion of the fuel ash remains in the boiler as slag on the furnace walls or as deposits in the convection sections and hoppers. In each case, a portion of the fuel sulfur content may remain with these ash accumulations to decrease the amount emitted as SO_2 or SO_3 in the flue gases. Although firm sulfur balance data are not available, from 5 to 25 percent of the fuel sulfur may be retained in a boiler, especially where a boiler is fired with high calcium content coal. Based on a comparison of calculated SO_x emissions to the experimental data, it appears that the results obtained in this program are in line with expectations for the boilers tested.

Sulfur trioxide determinations, which range between 8 and 16 ppm as shown on Tables 3-24, 3-25 and 3-26, are in accord with results obtained from other pulverized coal fired installations. The SO_3 values are within the anticipated range of up to five percent of total SO_x in the flue gas except for the data presented in Table 3-27 which appear to be too high, and are therefore suspect. For mixed coal-oil fuel firing, the sulfur dioxide emission data on Table 3-28 compare favorably with calculated SO_x emissions based on the sulfur content of the coal used at this plant. With oil firing, most or nearly all of the fuel sulfur appears in the flue gases so the SO_2 values shown in the table may be proportionately higher due to the small percentage of oil being fired during these tests.

Table 3-24

Public Service Electric and Gas Company
Mercer Station

Wet Chemistry SO_2/SO_3 Analyses
Of Flue Gases
Pulverized Coal Firing

Date (76)	Run No.	Boiler No.	Firing Condition	Load MWe	O_2, %	Calculated SO_x PPM	Wet Chemistry Analysis				SO_3/SO_2[1] Ratio, %
							SO_2		SO_3		
							ng/J	PPM	ng/J	PPM	
1-29	201	2	Base	160	4.5	924	487	611	8	8	1.3
					3.0		532	667	9	9	
1-29	202	2	Base	180	4.5		487	611	9	9	1.5
							532	667	10	10	
2-10	203	1	Low NO_x	290	2.4	990	567	711	10	10	1.4
							550	689	10	10	
2-10	204	1	Low NO_x	290	2.4		603	756	11	11	1.5
							585	733	11	11	
2-11	205	1	Base	210	4.4	1039	759	952	9	9	.9
							821	1030	10	10	
2-11	206	1	Base	210	4.4		736	923	11	11	1.2
							796	998	12	12	

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[1] ppm Ratio

Table 3-25

Public Service Company of Colorado
Comanche Station, Pueblo, Colorado

Wet Chemistry SO_2/SO_3 Analyses Of Flue Gases
Pulverized Coal Firing

Date	Boiler No.	Firing Condition	Load MWe	O_2, %	Calculated SO_x, PPM	Wet Chemistry Analysis SO_2 ng/J	Wet Chemistry Analysis SO_2 PPM	Wet Chemistry Analysis SO_3 ng/J	Wet Chemistry Analysis SO_3 PPM	SO_3/SO_2[1] Ratio, %
7-16-75	1	Base	331	4.0	499	215	270	15	15	5.6
				3.0		228	286	16	16	
7-16-75	1	Base	331	3.8		235	295	15	15	5.1
				3.0	376	246	308	16	16	
7-18-75	1	Base	332	--		225	282	--	--	
				--		219	275	9	9	3.4
7-30-75	1	Low NO_x	324	3.9	(2)	224	281	9	9	3.1
				3.0		236	296	9	9	
7-30-75	1	Low NO_x	324	3.9		225	282	10	10	3.5
				3.0		238	298	10	10	

---

(1) ppm Ratio

(2) Coal Data Not Available

Table 3-26

Salt River Project
Navajo Generating Station

Wet Chemistry SO_2/SO_3 Analyses Of Flue Gases
Pulverized Coal Firing

Date	Boiler No.	Firing Condition	O_2, %	Calculated SO_x, PPM	Wet Chemistry Analyses SO_2 ng/J	Wet Chemistry Analyses SO_2 PPM	Wet Chemistry Analyses SO_3 ng/J	Wet Chemistry Analyses SO_3 PPM	SO_3/SO_2[3] Ratio, %
6-12-75	2	Base	6.1	393	218	273	5	5	1.8
			3.0		263	330	6	6	
6-9-75	2	Base	5.2	450	230	288	--	--	---
			3.0		261	327[1]	--	--	
6-9-75	2	Base	6.0		210	263	--	--	---
			3.0		259	315[2]	--	--	
6-23-75	2	Low NO_x	3.8	(4)	158	198	9	9	4.7
			3.0		165	207	10	10	

---

(1) At Economizer Outlet

(2) At 360' Stack Elevation

(3) ppm Ratio

(4) Coal Data Not Available

Table 3-27

Southern Electric Generating Company
E. C. Gaston Station, Wilsonville, Alabama

Wet Chemistry SO_2/SO_3 Analyses Of Flue Gases
Pulverized Coal Firing

Date	Boiler No.	Firing Condition	Calculated SO_x, PPM	Wet Chemistry Analysis(1)				SO_3/SO_2(2) Ratio, %
				SO_2		SO_3		
				ng/J	PPM	ng/J	PPM	
1-31-75	2	Base	1072	726	910	129	129	14.2
1-31-75	2	Base	1193	552	692	127	127	18.4
1-30-75	2	Base	1415	883	1107	130	130	11.7

---

(1) Uncorrected Values

(2) ppm Ratio

Table 3-28

Potomac Electric Power Company
Morgantown Station, Morgantown, Maryland

Wet Chemistry SO_2 Analyses
Of Flue Gases
Coal/Oil Combination Firing

Test No.	Boiler No.	Sampling Location	Firing Condition	Wet Chemistry Analyses SO_2[1] ng/J	Wet Chemistry Analyses SO_2[1] PPM	Calculated SO_x, PPM[2]
1	1	At Exit Gas Duct	Base	1247	1563	1685
2	1	At Remote Pumping Unit	Base	1246	1562	1849
3	1	At End of Sampling Line At Van	Base	1253	1571	1751

---

(1) Uncorrected Values

(2) Calculated from Coal Analysis

4. CONCLUSIONS

In this section of the report, the overall conclusions of the field study results will be summarized. The effects of combustion modifications used for controlling NO_x and other pollutant emissions or gaseous and particulate emissions, furnace water-wall corrosion and boiler performance will be discussed based on the results obtained.

4.1 GASEOUS EMISSION MEASUREMENTS

In section 3.1 of this report, the results obtained in field studies on eight power generation combustion sources were presented for each individual unit tested. In this section, the conclusions based on emission results for the individual units will be presented, including overall correlations based on the results of the seven coal fired boilers tested.

Table 4-1 presents a summary of the NO_x emissions for coal fired boilers under baseline and "low NO_x" operation for the seven boilers tested during this contractual period. Widows Creek boiler No. 5 is a rear wall fired unit; Ernest C. Gaston boiler No. 1 is a horizontally opposed fired unit (equipped with the new B & W dual register low NO_x burners); Mercer boiler No. 1 is a twin furnace, front wall fired, wet bottom unit; while the remaining four boilers are of the tangential design type (three of these tangentially fired boilers are equipped with overfire air ports). Baseline emission data were also obtained on E. C. Gaston boiler No. 2 (a "sister" unit of Gaston No. 1) equipped with conventional pulverized wall burners. Gaseous measurements of O_2, NO_x and CO are listed for baseline operation, "low NO_x-I" (modified firing operation at full load) and "low NO_x-II" (modified firing operation at reduced load). Baseline NO_x emission levels are listed at both actual excess air levels and calculated for 20% excess air so that comparison between boilers can be made on the same operating basis. Note that correcting emissions to a 3% O_2 basis provide data on a constant dilution basis regardless of operating conditions.

A numerical example will help explain why correction of actual NO_x emissions to a 3% O_2 dry basis for dilution and the normalization of baseline operation emission levels are useful. Table 4-2 contains baseline operation emission data from Navajo No. 2 Unit for three excess air level operations: 116%, 120% and 129% stoichiometric air. NO_x emissions test data are listed on the bases: ppm NO_x (as measured), ppm NO_x (3% O_2 dry basis) and lbs. $NO_x/10^6$ BTU. The % change (Δ_i) in emissions are listed for the change in operation from 116% to 120% and 120% to 129% stoichiometric air. Note that the Δ_s for ppm NO_x (3% O_2, dry) and lb. $NO_x/10^6$ BTU are identical since they are both on a mass emission basis while the ppm NO_x, as measured, Δ_s are lower because of a dilution factor. Thus, a correction for dilution is necessary to put the data on a comparable mass emission basis. It should also be noted that if the NO_x data were not normalized to 120% (or some other arbitrary fixed level), Navajo No. 2 Unit operating at 29% excess air would give a 23% higher NO_x emission level than an identical emitting boiler which operated at 20% excess air under baseline operation. Thus, normalizing baseline operation to a constant excess air level removes one extraneous operating variable so that the effect of other variables on NO_x emissions such as type of firing, size, etc. can be more easily analyzed.

TABLE 4-1

SUMMARY OF NO_x EMISSIONS FOR COAL FIRED BOILERS

	Boiler	Operating Mode (Gross Load - MWe)	% O_2	NO_x Emissions ppm (3% O_2)	NO_x Emissions Lb./10^6 BTU	NO_x Emissions ng/J	ppm CO (3% O_2)
1.	Widows Creek No. 5 (RW)(a)	Base - 125	4.0	597(567)(b)	0.81	349	29
		"Low NO_x - I" - 125	3.2	468	0.64	274	88
		"Low NO_x - II" - 100	5.3	305	0.41	178	285
2.	Ernest C. Gaston No. 1 (HO)(a) (Low NO_x Burners)	Base (NO.2 Unit) - 270	4.3	591(491)(b)	0.53	227	26
		"Low NO_x - I" - 270	2.4	278	0.38	163	65
		"Low NO_x - II" - 190	1.6	182	0.25	106	329
3.	Navajo No. 2 (T)(a) (Overfire Air Ports)	Base - 800	4.8	492(400)(b)	0.67	288	64
		"Low NO_x - I" - 802	3.6	282	0.38	165	330
4.	Comanche No. 1 (T)(a) (Overfire Air Ports)	Base - 323	4.0	417(370)(b)	0.57	244	27
		"Low NO_x - I" - 333	3.7	261	0.35	153	35
5.	Barry No. 2 (T)(a) (Overfire Air Ports)	Base - 130	4.9	341(250)(b)	0.46	199	22
		"Low NO_x - I" - 129	3.3	189	0.26	111	49
6.	Morgantown No. 1 (T)(a)	Base(c) - 570	4.9	552(534)(b)	0.75	323	21
		"Low NO_x - I" (d) - 572	4.7	403	0.55	236	20
7.	Mercer No. 1 (FW)(a)	Base - 290	3.9	1383(1354)(b)	1.88	809	22
		"Low NO_x - I" - 220	3.4	356	0.48	208	218
		"Low NO_x - II" - 160	4.2	351	0.48	205	455

(a) Types of Firing: RW, rear wall; HO, horizontally opposed; T, tangential; FW, front wall.

(b) Baseline NO_x emissions calculated for 20% excess air operation.

(c) Fuel burned = 93% coal, 7% oil.

(d) Fuel burned = 74% coal, 26% oil.

TABLE 4.2

NAVAJO NO. 2 - BASELINE OPERATION EMISSION DATA

	1	Δ_1	2	Δ_2	3
% Stoichiometric Air	116 (3.0% O_2)	+3.4%	120 (3.6% O_2)	+7.5%	129 (4.8% O_2)
PPM NO_x (As Measured)	360	+7.5%	387	+14.2%	442
PPM NO_x (3% O_2, Dry)	360	+11.1%	400	+23.0%	492
Lbs. $NO_x/10^6$ BTU	0.490	+11.1%	0.544	+23.0%	0.669

The wall fired boilers (Widows Creek No. 5, Gaston No. 2 and Mercer No. 1) under baseline operating conditions produced NO_x emissions above the 301 ng/J (0.7 lb./10^6 BTU) level of the NSPS for coal-fired steam generators. However, under modified combustion operation the dry bottom, wall fired boilers, Widows Creek No. 5 (low excess air, staged firing) and Gaston No. 1 (low NO_x Babcock & Wilcox burners) emitted NO_x below the level of NSPS under full load operation, while the wet bottom Mercer boiler No. 1 required a 20% load reduction and low excess air, staged firing operation to reduce NO_x emissions below 0.7 lb./10^6 BTU. At reduced load (by 20%) Widows Creek boiler No. 5 produced NO_x emissions as low as 179 ng/J (305 ppm) in short term tests, i.e., 49% below the baseline NO_x level at full load. Gaston boiler No. 1 equipped with newly designed dual register burners, produced 36% lower NO_x emissions than Gaston boiler No. 2 (a sister boiler equipped with conventional burners) under baseline conditions. Modified firing operation of Gaston No. 1 unit at full load and at reduced load lowered NO_x emissions by 59% and 69%, respectively, compared to baseline operation with the conventional burners. For the wet bottom Mercer boiler No. 1 operated at 20% reduced load, staged combustion with low excess air reduced NO_x emissions by 74% from the baseline emission level.

Under full load, baseline operation (cooling air only), the three tangentially fired boilers that are equipped with overfire air ports met the 301 ng/J (0.7 lb./10^6 BTU) NSPS for NO_x. Morgantown boiler No. 1 emitted NO_x slightly above this level under baseline firing conditions with coal fuel. Modified firing using the overfire air ports at low overall excess air resulted in reductions of 37 to 45% in NO_x emissions. Staged firing of Morgantown boiler No. 1 reduced NO_x emissions by 27% for this particular unit. Comparison of baseline NO_x emissions normalized to 20% excess air for the three boilers equipped with OFA to those measured on four tangentially fired boilers in previous ER&E field test studies show an 18% NO_x reduction due to cooling air.

The ranges of NO_x emissions measured under normal firing operating conditions as a function of excess air level (% O_2 in the flue gas) are shown in Figure 4-1. The line representing the wet bottom Mercer No. 1 boiler (labeled ME) is plotted using the right hand NO_x scale while all of the other boilers are plotted using the left hand ordinate values.

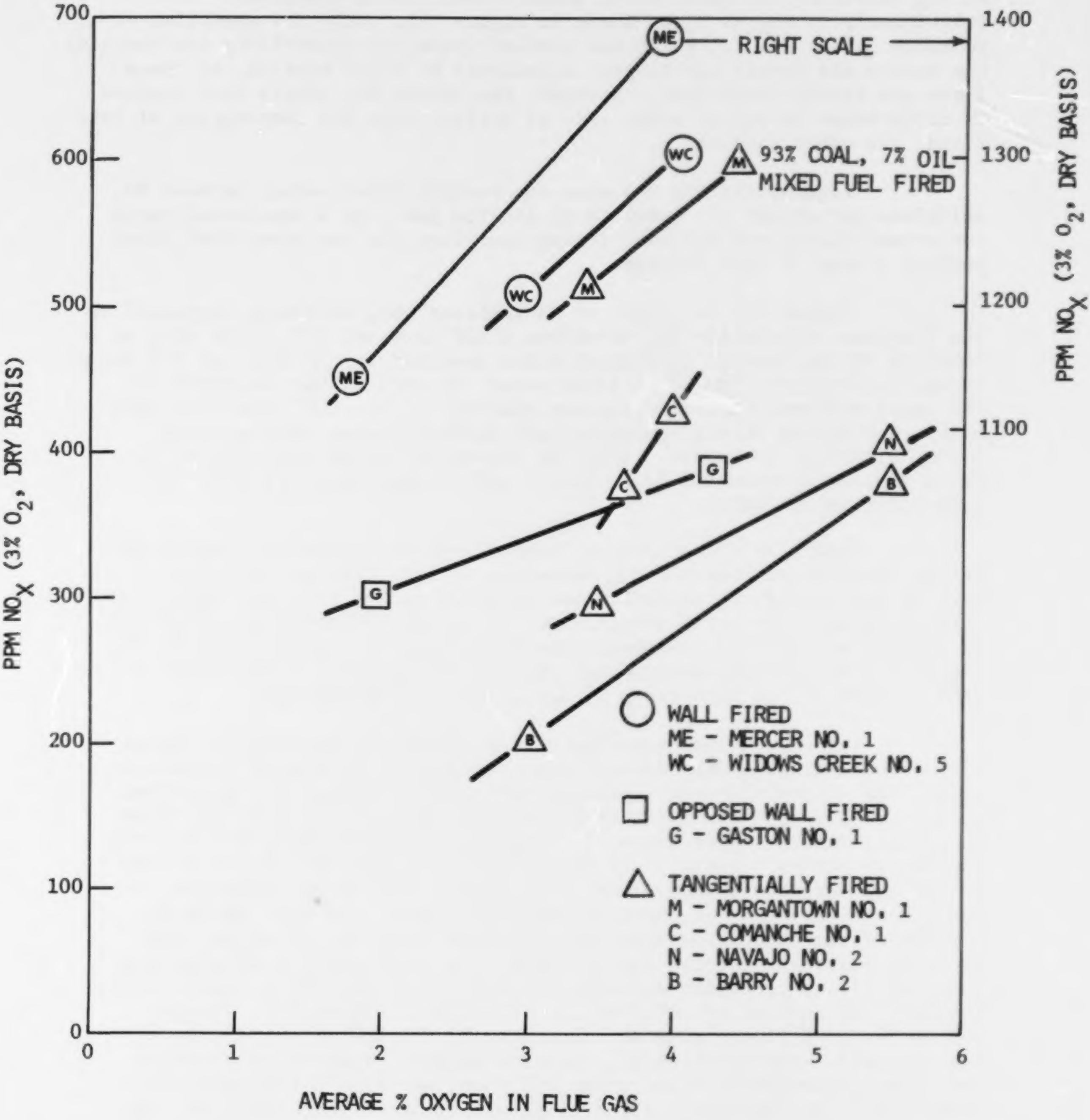

Figure 4-1. PPM NO_x vs % O_2 in flue gas from coal-fired boilers under normal firing operation.

As discussed in section 3.1, excess air had a significant effect on NO_x emissions for each boiler under normal firing operation. The relationship of NO_x vs O_2 is shown in Figure 4-1. With the exception of Comanche boiler No. 1, (which had limited operating flexibility for changing the excess air level) the slopes, calculated by least squares, of these lines are fairly consistent. However, the actual NO_x levels vary because of differences in boiler size, type of firing, type and composition of coal fired, and other factors.

Figures 4-2 and 4-3 show the overall relationship between NO_x emissions and excess air level (% O_2 in flue gas), on a consistent basis for normal firing and modified firing operation for the seven coal fired boilers tested in this program.

Figure 4-2 is a plot of "normalized" NO_x emissions expressed as the fraction of baseline NO_x emissions (full load and 20% excess air) as a function of the average O_2 concentration measured in the flue gas for normal firing conditions. The solid lines shown for each boiler are based on the least-squares, linear regression analysis of all full load test runs made under normal firing operation (all burners firing coal and with closed overfire air ports). With the exception of the Comanche boiler No. 1 mentioned above and Barry No. 2, all of the lines fit within a relatively narrow band.

Figure 4-3 is a plot of "normalized" NO_x emissions (expressed as the fraction of baseline NO_x emissions at full load and 20% excess air) vs the average O_2 concentration measured in the flue gas under modified combustion operating conditions. Thus, the ordinates are identical in Figures 4-2 and 4-3. However, the least squares regression lines of Figure 4-3 do not necessarily pass through the normalized NO_x value of 100% at 3.6% O_2, as they must, by definition, in Figure 4-2.

Figure 4-3 indicates the strong effect of lowering the excess air on NO_x emissions when boilers are operated in the staged combustion mode. The slopes of these lines are very similar except for Morgantown boiler No. 1 (which was fired with a mixture of coal and oil) and Barry No. 2 unit (which has overfire air ports located relatively far from the top row of active burners). It should be noted that all of the boilers tested had baseline NO_x emission rates higher than those normalized to 20% excess air (used for constructing Figure 4-3), and that optimized, modified firing operation generally produced lower NO_x operation than shown by the least squares lines. Thus, the improvement resulting from modified firing operation compared to actual baseline NO_x emission levels averaged 38% instead of 26% based on the data in Figure 4-3. Mercer boiler No. 1 (ME), the only wet bottom boiler tested in this program, had unusually high baseline NO_x emission levels. This is reflected by the large reduction obtained under 80% load, modified firing operating conditions. An additional point to recall again is that three of the tangentially fired boilers are equipped with overfire air ports, which resulted in an average 18% reduction normalized baseline NO_x emissions compared to the results for the tangentially fired boilers tested previously (2). This reduction in baseline NO_x emissions is due to the use of cooling air through the overfire air ports.

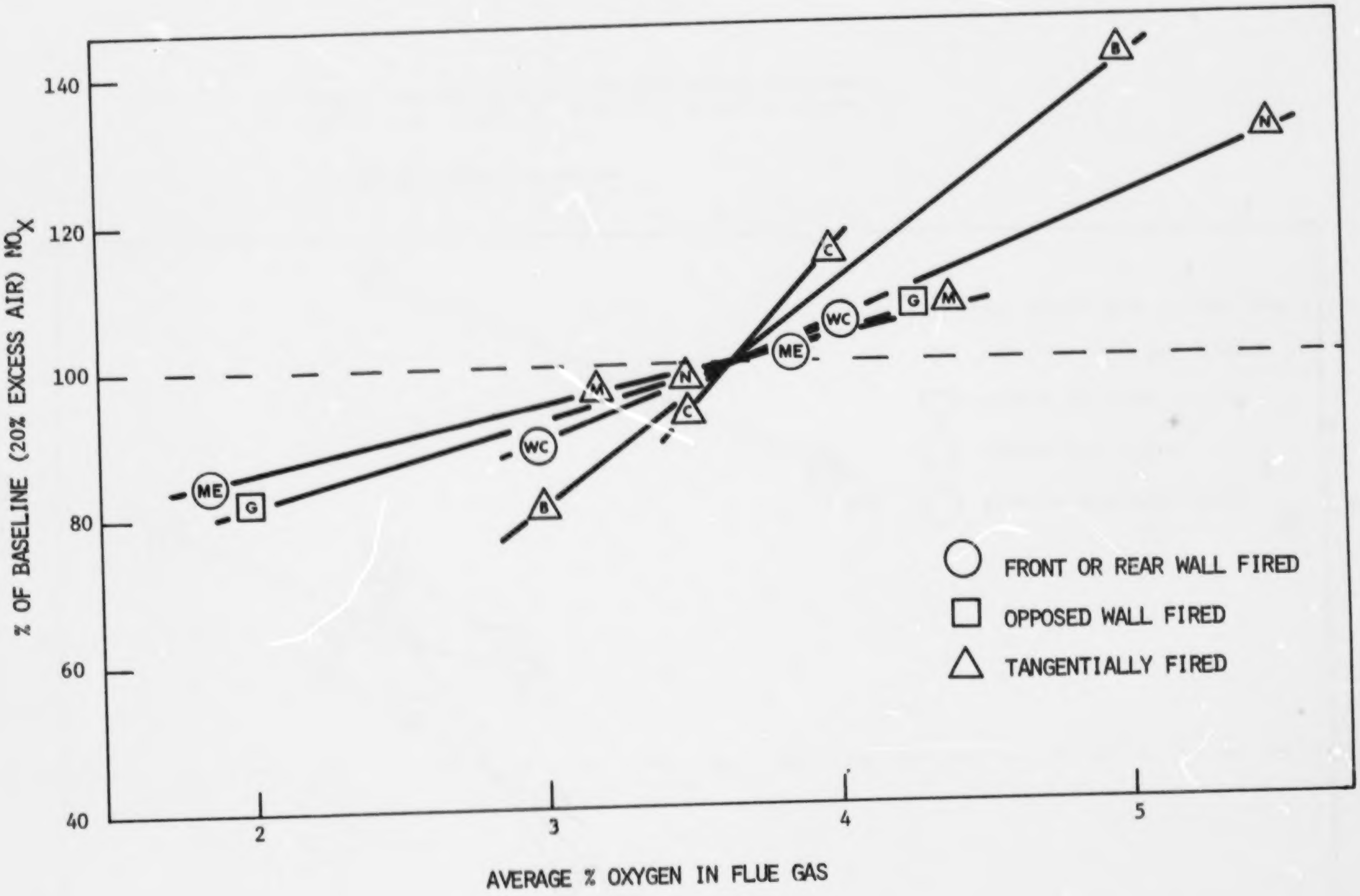

Figure 4-2. Effect of excess air level on NO$_x$ emissions for coal fired boilers under normal firing operations.

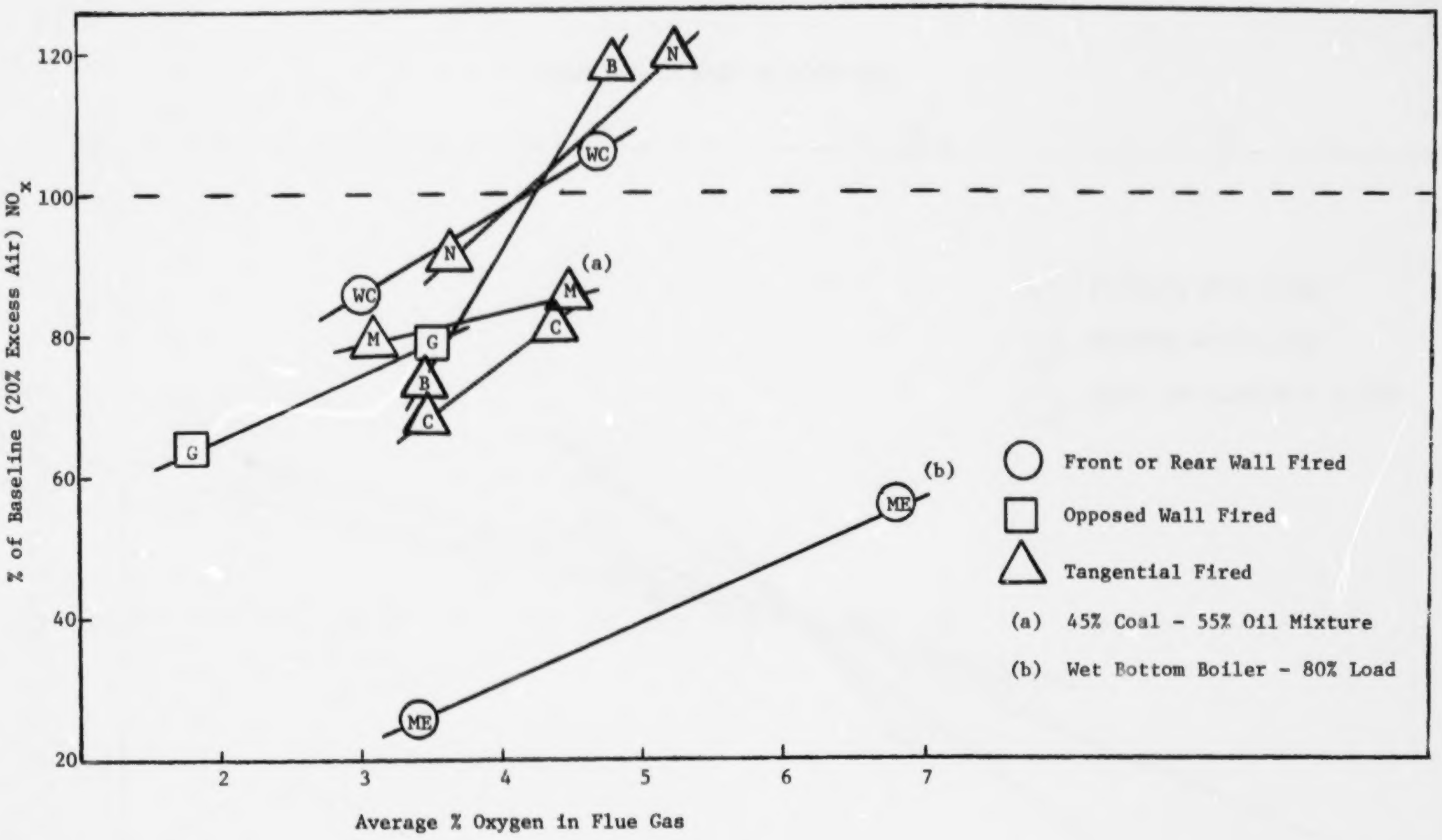

Figure 4-3. Effect of excess air on NO_x emissions of coal fired boilers under modified firing conditions.

The results obtained on mixed fuel fired boilers indicate that NO_x emission levels increased as the fraction of coal in coal-oil and coal-gas mixtures increases. However, the relationship between NO_x emissions and fuel coal content is not linear. Additional test data are required to establish a more reliable correlation for predicting NO_x emissions from mixed fuel fired units than the single assumption of linear dependence.

A large 50 MWe General Electric gas turbine was tested under normal operating conditions while firing fuel oil. NO_x emissions were about 219 ng/J (375 ppm) at full load, 234 ng/J (400 ppm) at peak load (54 MWe) with reductions to about 190 and 146 ng/J (325 and 250 ppm) at 50% and 20% of full load operation, respectively. Thus, in the absence of NO_x control modifications, load reduction was found to exhibit a strong influence on NO_x emissions.

This section can be summerized as follows:

- Conventional wall and tangentially fired boilers that were not designed with special NO_x reduction features did not meet the NSPS standard of 0.7 lb/10^6 BTU for NO_x emissions under full load, baseline operation.
- Wall and tangentially fired boilers designed with NO_x reduction features such as low turbulence, dual register burners or overfire air ports were capable of meeting the NSPS for NO_x emissions under baseline operations.
- A wall-fired boiler (Gaston No. 1) retrofitted with Babcock and Wilcox, dual register burners emitted substantially less NO_x (377 ppm vs 591 ppm or -36%) than a similar boiler equipped with conventional burners.
- Three tangentially fired boilers equipped with overfire air ports were capable of reducing NO_x emissions by 37 to 45% under low excess air, staged firing operation (282 ppm vs 492 ppm, 261 ppm vs 417 ppm and 198 ppm from 341 ppm).
- Low excess air, staged firing operation on conventional wall fired units reduced NO_x emissions significantly on both dry and wet bottom units. The dry bottom unit met the NSPS for NO_x emissions at full load under this operation while the wet bottom unit (with extremely high baseline emissions) was forced to reduce load to meet the 0.7lb/10^6 BTU NO_x emission standard for new boilers.
- NO_x emissions increased from mixed-fuel fired boilers as the fraction of coal in coal-oil and coal-gas mixtures increased. However, the relationship between NO_x emissions and fuel coal content was not linear in the two units tested to date.
- The firing pattern used in low excess air, staged firing operation in boilers without overfire air ports, had a significant influence on the level of NO_x reduction obtained. Firing patterns utilizing top burners on air only, were nore effective than firing patterns with middle or lower row burners on air only. In addition, the use of maximum secondary air register openings on air only burners while simultaneously reducing air register openings on operating burners had a beneficial effect on the level of NO_x emissions.

4.2 SIDE EFFECTS OF COMBUSTION MODIFICATIONS

As discussed in Section 3, the modified combustion techniques studied for controlling NO_x emissions did not produce major, and for the most part, did not produce significant adverse side-effects in short-term, 300-hour test runs. Thus, particulate mass loading and size distribution, carbon on fly ash, and boiler efficiency have not changed significantly when comparing low NO_x modified combustion operation with baseline conditions. Long-term testing to determine furnace tubewall corrosion rates by actual tube wall thickness measurements is required to establish whether fuel rich, staged firing of different coal types used in different boiler design types results in undue tubewall corrosion rates.

5. REFERENCES

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4. Environmental Protection Agency, Standards of Performance for New Stationary Sources," Method 5, Published in the Federal Register, December 23, 1971, Vol. 36, Number 247, p. 24888.

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APPENDIX A

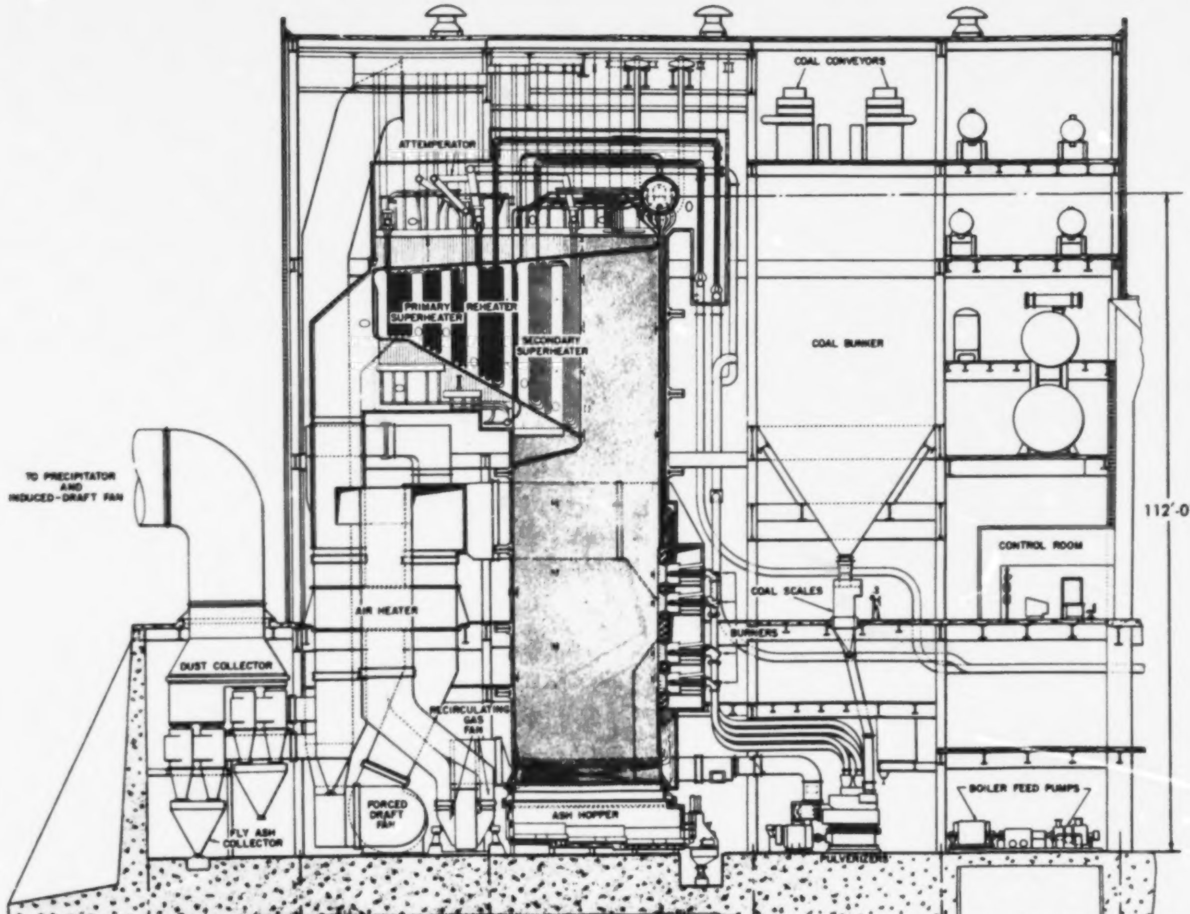
CROSS SECTIONAL DRAWINGS OF TYPICAL UTILITY BOILERS

Typical utility boiler designs representative of the types of boilers tested in this program are shown in the cross sectional drawings in Figures 1 through 3 of Appendix A. Typical front wall, horizontally opposed and tangentially fired boilers are shown in Figures 1, 2 and 3, respectively.

APPENDIX A

FIGURE 1

TYPICAL FRONT WALL FIRED BOILER

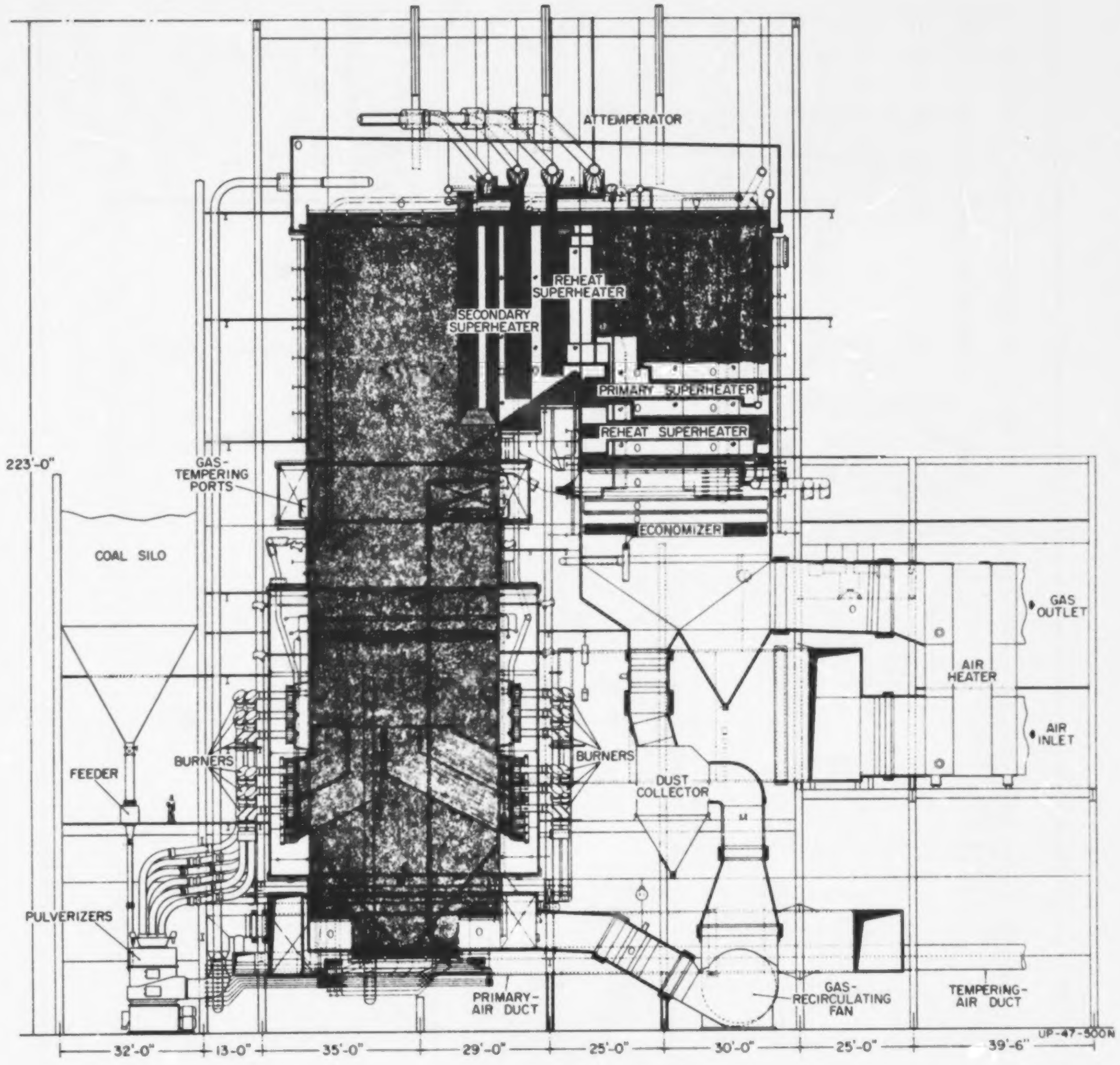

COAL CONVEYORS
ATTEMPERATOR
PRIMARY SUPERHEATER
REHEATER
SECONDARY SUPERHEATER
COAL BUNKER
TO PRECIPITATOR AND INDUCED-DRAFT FAN
112'-0"
CONTROL ROOM
COAL SCALES
AIR HEATER
BURNERS
DUST COLLECTOR
RECIRCULATING GAS FAN
BOILER FEED PUMPS
FORCED DRAFT FAN
ASH HOPPER
FLY ASH COLLECTOR
PULVERIZERS
27'-0"
32'-0"
44'-0"
32'-0"
30'-0"

DRAWING FURNISHED THROUGH THE COURTESY OF
THE BABCOCK AND WILCOX COMPANY

APPENDIX A

FIGURE 2

TYPICAL HORIZONTALLY OPPOSED FIRED BOILER

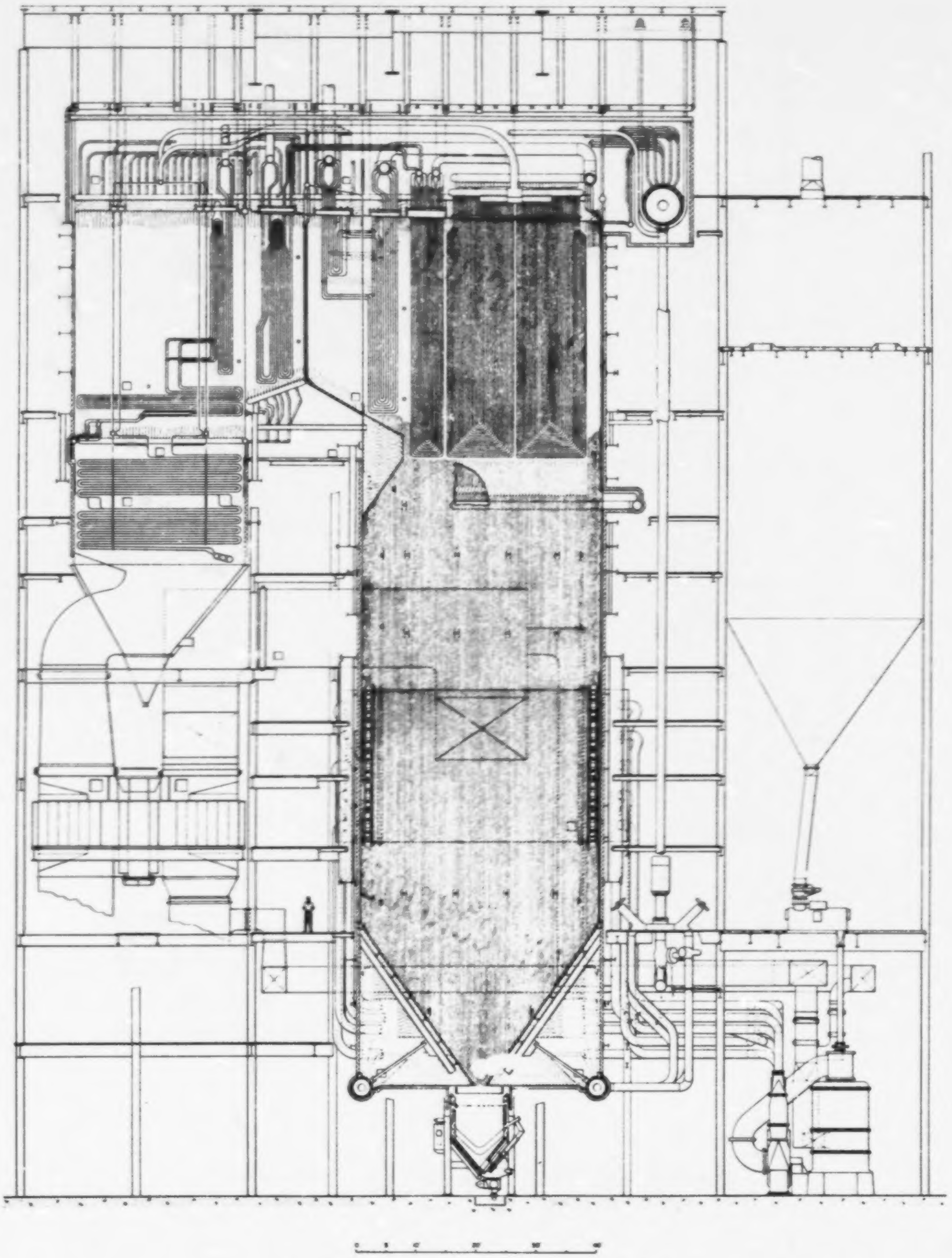

ATTEMPERATOR
REHEAT SUPERHEATER
SECONDARY SUPERHEATER
PRIMARY SUPERHEATER
REHEAT SUPERHEATER
223'-0"
GAS-TEMPERING PORTS
ECONOMIZER
COAL SILO
GAS OUTLET
AIR HEATER
AIR INLET
BURNERS
BURNERS
FEEDER
DUST COLLECTOR
PULVERIZERS
PRIMARY-AIR DUCT
GAS-RECIRCULATING FAN
TEMPERING-AIR DUCT
UP-47-500N
32'-0"
13'-0"
35'-0"
29'-0"
25'-0"
30'-0"
25'-0"
39'-6"

DRAWING FURNISHED THROUGH THE COURTESY OF
THE BABCOCK AND WILCOX COMPANY

APPENDIX A

FIGURE 3

TYPICAL TANGENTIALLY FIRED BOILER



DRAWING FURNISHED THROUGH THE COURTESY OF
COMBUSTION ENGINEERING, INC.

APPENDIX B

CONVERSION FACTORS

ENGLISH TO SI UNITS

To Convert From	To	Multiply By*
Btu	Gigajoule, GJ	1.055 056 E-06
Btu/h	Megawatt, MW	6.330 336 E-02
Btu/lb	Gigajoule/kilogram, GJ/kg	2.326 000 E-06
Btu/lb	Calories/gram, cal/g	5.559 273 E-01
Pounds/square inch	Megapascal, MPa Kilopascal, kPa	6.894 757 E-03 6.894 757 E+00
Pounds/hour, lb/h	Kilogram/hour, kg/h	4.535 924 E-01
Pounds/hour, lb/h	Metric tons/hour, t/h	4.535 924 E-04
Tons (short)	Metric tons, t	9.071 847 E-01
Pounds, lb	Kilogram, kg	4.535 924 E-01
Feet, ft	Metre, m	3.048 000 E-01
Square Feet, ft^2	$Metres^2$, m^2	9.290 304 E-02
Inches, in	Centimetres, cm	2.540 000 E+00
Inches, in	Metre, m	2.540 000 E-02
Grains/cubic foot	$Milligrams/metre^3$, mg/m^3	2.288 351 E-01
Cubic feet, ft^3	$Metre^3$, m^3 $Decimetre^3$, dm^3	2.831 685 E-02 2.831 685 E+01
Gallons	$Metres^3$, m^3 $Decimetre^3$, dm^3	3.785 412 E-03 3.785 412 E+00

*Numbers expressed in power-of-ten notation using E ± xx to indicate the power of ten. For example:

$$1.055\ 056\ E-06 = 1.055\ 056 \times 10^{-6} = .000001055056$$

APPENDIX B

CONVERSION FACTORS

English and Metric Units to SI Units

To Obtain	From	Multiply By
ng/J	lb/MBtu	430
ng/J	g/MCal	239
$GJ \cdot hr^{-1} \cdot m^{-2}$	MBH/ft^2	11.356
$GJ \cdot hr^{-1} \cdot m^{-3}$	MBH/ft^3	37.257
GJ/hr	10^3 lb/hr* or 10^6 Btu/hr	1.055
m	ft	0.3048
cm	in	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
Kg	lb	0.4536
Celsius	Fahrenheit	$t_c = 5/9\ (t_F-32)$
Kelvin		$t_K = 5/9\ (t_F-32) + 273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895X10^3)$
Pa	psia	$P_{pa} = (P_{psia})(6.895X10^3)$
Pa	iwg (39.2°F)	$P_{pa} = (P_{iwg})(249.1)$

To Obtain ng/J of	Multiply Concentration in ppm at 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NO_x (as equivalent NO_2)	0.510
SO_2 or SO_x	0.709
Oil Fuel	
CO	0.341
HC	0.195
NO or NO_x (as equivalent NO_2)	0.561
SO_2 or SO_x	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NO_x (as equivalent NO_2)	0.584
SO_2 or SO_x	0.850

---

*lb/hr of equivalent saturated steam

APPENDIX B

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10^6 Btu	GJ	0.948
MBH/ft^2	$GJ \cdot hr^{-1} \cdot m^{-2}$	0.08806
MBH/ft^3	$GJ \cdot hr^{-1} \cdot m^{-3}$	0.02684
Btu	gm cal	3.9685×10^{-3}
10^3 lb/hr* or MBH	GJ/hr	0.948
lb/MBtu	ng/J	0.00233
ft	m	3.281
in	cm	0.3937
ft^2	m^2	10.764
ft^3	m^3	35.314
lb	Kg	2.205
Fahrenheit	Celsius	$t_F = 9/5(t_c)+32$
	Kelvin	$t_F = 1.8K - 460$
psig	Pa	$P_{psig} = (P_{pa})(1.450X10^{-4})-14.7$
psia	Pa	$P_{psia} = (P_{pa})(1.450X10^{-4})$
iwg (39.2°F)	Pa	$P_{iwg} = (P_{pa})(4.014X10^{-3})$

*lb/hr of equivalent saturated steam

To Obtain ppm at 3% O_2 of	Multiply Concentration in ng/J by
Natural Gas Fuel	
CO	3.23
HC	5.65
NO or NO_x	1.96
SO_2 or SO_x	1.41
Oil Fuel	
CO	2.93
HC	5.13
NO or NO_x	1.78
SO_2 or SO_x	1.28
Coal Fuel	
CO	2.69
HC	4.69
NO or NO_x	1.71
SO_2 or SO_x	1.18

APPENDIX C

OPERATING AND GASEOUS EMISSION DATA SUMMARIES

This section of the report contains 7 tables summarizing the operating and gaseous emission data by test run for each of the 7 coal fired boilers and a gas turbine tested.

Table	Boiler
1	Widows Creek No. 5
2	Ernest C. Gaston No. 1 and No. 2
3	Navajo No. 2
4	Comanche No. 1
5	Barry No. 2
6	Morgantown No. 1
7	Mercer No. 1
8	Morgantown Gas Turbine No. 3

Percent oxygen and % carbon dioxide are listed on an as measured basis. Carbon monoxide and gaseous hydrocarbons are listed on a ppm (3% O_2, dry) basis. NO_x emissions are listed on a ppm (3% O_2, dry) basis, pounds per 10^6 Btu and nanograms per joule bases. The conversion factor used for adjusting ppm (3% O_2, dry) to pounds per 10^6 Btu is 0.00136. The conversion factor for converting pounds NO_x per 10^6 Btu to ng/J is 430.

APPENDIX C

TABLE 1

SUMMARY OF OPERATING AND EMISSION DATA - WIDOWS CREEK, BOILER NO. 5

(125 MWe, Front Wall, Pulverized Coal Fired)

Date and Run No. (1975)	Operating Conditions					Flue Gas Measurements						
						O_2	NO_x			CO_2	CO	Temp.
	Gross Load (MWe)	Firing Pattern-(Burners on Air Only)(a)	Sec. Air Registers (% Open)	Excess Air Level	% Stoich. Air to Active Burners (b)	%	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	Nanogram Per Joule	%	PPM (3% O_2, Dry)	Kelvin
9/25-1	105	S_1-None	60	Normal	134	5.4	603	0.82	353	12.4	29	661
2	118	S_1-None	60	Low	117	3.2	502	0.68	294	14.6	403	630
3	120	S_1-None	20	Normal	119	3.5	574	0.78	336	14.1	54	651
4	121	S_1-None	20	Low	117	3.2	548	0.75	320	14.2	62	743
9/26-1A	121	S_1-None	60	Normal	123	4.0	597	0.81	349	14.0	43	648
5	121	S_2-(A_1A_4)	60	Low	101	3.0	486	0.66	284	14.0	124	644
6	117	S_3-(C_1C_4)	60	Low	113	4.8	639	0.87	374	14.0	35	753
7	119	S_4-(B_1B_4)	20	Low	105	3.6	517	0.70	302	14.7	317	646
8	120	S_5-(D_1D_4)	20	Low	105	3.6	580	0.79	339	14.3	31	647
9/27-9	115	S_5-(D_1D_4)	60	Low	104	3.4	598	0.81	350	14.5	52	647
10	110	S_4-(B_1B_4)	60	Low	108	4.0	521	0.71	305	13.5	74	644
11	112	S_3-(C_1C_4)	20	Low	108	4.1	474	0.64	277	13.2	37	647
12	120	S_2-(A_1A_4)	20	Low	102	3.2	468	0.64	274	14.6	88	645
10/2-13	102	S_1-None	60	Normal	135	5.5	660	0.90	386	12.8	33	650
14	98	S_1-None	60	Low	116	3.0	462	0.63	270	14.5	63	627
15	98	S_1-None	20	Normal	134	5.4	667	0.91	390	13.0	18	643
16	97	S_1-None	20	Low	110	2.1	381	0.52	223	15.6	563	621
10/3-17	99	S_6-($A_1A_4D_1D_4$)	60	Low	88	3.2	365	0.50	213	14.3	283	628
18	100	S_7-($A_1A_4B_2B_3$)	60	Low	87	3.0	374	0.51	219	14.4	208	627
19	99	S_8-($A_1A_4B_1B_4$)	20	Low	88	3.3	316	0.43	184	14.5	106	633
20	100	S_9-($A_1A_2A_3A_4$)	20	Low	100	5.3	305	0.41	178	13.2	503	615
10/4-21	99	S_9-($A_1A_4A_3A_2$)	60	Low	94	4.5	329	0.45	192	13.2	155	632
22	100	S_8-($A_1A_4B_1B_4$)	60	Low	94	4.4	368	0.50	215	13.3	82	628
23	100	S_6-($A_1A_4D_1D_4$)	20	Low	93	4.3	421	0.57	246	13.6	63	635
24	101	S_7-($A_1A_4B_2B_3$)	20	Low	88	3.3	302	0.41	176	13.8	103	628
10/7-1B	125	S_1-None	60	Low	112	2.4	409	0.56	239	15.5	710	636
10/8-1C	125	S_1-None	60	Low	113	2.5	441	0.60	258	14.6	618	640
10/14-12B	124	S_2-(A_1A_4)	20	Low	97	2.2	465	0.63	272	16.0	87	640
10/15-12C	125	S_2-(A_1A_4)	20	Low	99	2.5	412	0.56	241	15.5	214	642
10/17-12E	108	S_2-(A_1A_4)	20	Low	105	3.6	561	0.76	328	14.4	78	635
10/22-12F	132	S_2-(A_1A_4)	20	Low	97	2.2	504	0.69	298	15.5	429	675

(a) Four rows of four burners each; A row on top to D row at bottom.
(b) Based on assumption that equal amounts of air flow through all active and inactive burners.
(c) HC were not measured due to instrument problems.

APPENDIX C

TABLE 2

SUMMARY OF OPERATING AND EMISSION DATA - ERNEST C. GASTON, BOILERS NO. 1 AND 2

(270 MWe, Horizontal Opposed, Pulverized Coal Fired)

Date and Run No. (1975-1976)	Operating Conditions							Flue Gas Measurements							
	Gross Load (MWe)	Firing Pattern (Burners on Air Only)	Air Register Setting			Excess Air Level	% Stoich. Air to Active Burners(d)	O_2	NO_x			CO_2	CO	HC	Temp.
			Sec.	Tert.	Vanes %(c)			%	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	Nanogram Per Joule	%	PPM (3% O_2, Dry)	PPM (3% O_2, Dry)(e)	Kelvin
11/14-1	270	S_1-None	70	100	90	Normal	125	4.3	389	0.53	227	13.9	26	--	688
2	270	S_1-None	70	100	90	Low	112	2.4	278	0.38	163	14.9	65	--	686
3	270	S_1-None	50	100	100	Low	112	2.4	289	0.39	169	15.5	46	--	684
11/15-4	270	S_1-None	30	100	100	Low	114	2.6	329	0.45	192	14.7	55	--	699
5	270	S_1-None	100	100	100	Low	112	2.4	336	0.46	196	15.1	63	--	683
6	270	S_1-None	50	100	90	Low	112	2.3	318	0.43	186	15.5	79	--	684
7	270	S_1-None	50	50	90	Low	113	2.5	362	0.49	212	15.0	36	--	683
11/18-8	270	S_1-None	30	50	90	Low	111	2.2	312	0.42	188	14.8	44	--	642
9	270	S_1-None	100	50	90	Low	110	2.0	296	0.40	173	15.3	59	--	684
11/20-10(a)	270	S_1-None	--	--	--	Normal	125	4.3	600	0.82	351	14.2	32	--	810
11/22-11	250	S_2-(E Mill)	70	100	90	Normal	100	3.6	289	0.39	169	14.0	45	--	679
12	250	S_2-(E Mill)	70	100	90	Low	95	2.6	257	0.35	150	14.5	178	--	676
13	195	S_3-(E,B Mills)	70	100	90	Normal	80	3.6	240	0.33	140	13.9	39	--	668
14	190	S_3-(E,B Mills)	70	100	90	Low	72	1.6	182	0.25	106	14.8	329	--	658
15	187	S_3-(E,B Mills)	70	70	90	Low	72	1.8	200	0.27	117	14.8	245	--	658
16	236	S_4-(B Mill)	70	100	90	Low	91	1.9	240	0.33	140	15.3	162	--	669
12/9-17(b)	204	S_1-None	70	100	90	Normal	129	4.9	325	0.44	190	14.0	21	--	--
18(b)	206	S_1-None	70	100	90	Maximum	149	7.0	454	0.62	265	11.9	21	--	--
19(b)	206	S_1-None	30	100	90	Maximum	147	6.8	451	0.61	264	11.1	25	--	--
20(b)	204	S_1-None	30	100	90	Normal	122	3.9	295	0.40	172	13.6	28	--	--
1/15-21	273	S_1-None	30	100	90	Normal	120	3.7	377	0.51	220	14.1	36	0	--
22	270	S_1-None	50	100	90	Normal	120	3.6	409	0.56	239	14.8	32	--	--
23	270	S_1-None	70	100	90	Normal	122	3.9	356	0.48	208	14.5	31	--	--
24	270	S_1-None	100	100	90	Normal	120	3.7	349	0.47	204	14.8	33	2	--
1/16-25	268	S_1-None	70	100	90	Normal	121	3.8	390	0.53	228	15.8	--	2	--
1/17-26	270	S_1-None	70	100	90	Normal	122	3.9	349	0.47	204	14.0	39	--	663
1/20-27	268	S_1-None	70	100	90	Normal	122	3.9	316	0.43	185	14.3	34	2	639
1/22-28(a)	272	S_1-None	--	--	--	Normal	124	4.2	584	0.79	341	15.2	--	17	--
1/23-29(a)	268	S_1-None	--	--	--	Normal	123	4.1	572	0.78	334	15.2	20	7	--
1/29-30(a)	270	S_1-None	--	--	--	Normal	124	4.3	606	0.82	354	14.8	21	2	--
2/3-34	148	S_3-(E,B Mills)	70	100	90	Normal	97	6.9	148	0.20	87	12.6	43	3	626
2/4-35	269	S_1-None	70	100	90	Normal	125	4.4	372	0.51	217	13.5	22	1	631
2/5-36	208	S_4-(B Mill)	70	100	90	Normal	101	3.8	301	0.41	176	15.1	27	2	621
37	243	S_1-None	70	100	90	Normal	122	3.9	324	0.44	189	15.9	49	2	629

(a) Boiler No. 2 data.
(b) Load limited to 205 MWe due to excess turbine vibration.
(c) 50% - No spin, 100% - maximum counterclockwise spin of secondary air.
(d) Based on assumption that equal amounts of air flow through all active and inactive burners.
(e) Hydrocarbons were measured on each test but values negligible except where indicated.

APPENDIX C

TABLE 3

SUMMARY OF OPERATING AND EMISSION DATA - NAVAJO, BOILER NO. 2

(800 MWe, Tangential, Pulverized Coal Fired)

Date and Run No. (1975)	Operating Conditions							Flue Gas Measurements							
	Gross Load (MWe)	Excess Air Level	Firing Pattern				Burner Tilt	O_2	NO_x			CO_2	CO	HC	Temp.
			Symbol(a)	Overfire Air		No. Active Burners									
				% Open	Tilt			%	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	Nanogram Per Joule	%	PPM (3% O_2, Dry)	PPM (3% O_2, Dry)	Kelvin
5/29-3	803	Normal	S_1	10	Horiz.	56	+10°	4.9	366	0.50	214	13.5	34	1	666
5/30-6	802	Low	S_1	10	Horiz.	56	+10°	4.0	335	0.46	196	14.0	70	3	658
4	801	Low	S_1	10	Horiz.	56	Horiz.	4.2	309	0.42	181	13.5	94	4	656
5	797	Low	S_1	10	Horiz.	56	-15°	3.8	314	0.43	184	14.5	137	3	658
6A	800	Low	S_1	10	Horiz.	56	+25°	3.8	411	0.56	240	14.8	288	3	665
3A	799	Normal	S_1	10	Horiz.	56	+25°	4.8	492	0.67	288	14.0	64	3	666
1	798	Normal	S_1	10	Horiz.	56	Horiz.	4.9	343	0.47	201	13.7	54	4	666
6/2-11	795	Normal	S_4	25	+10°	56	+10°	4.0	332	0.45	194	13.4	94	4	652
13	795	Normal	S_5	50	+10°	56	+10°	3.9	310	0.42	181	13.3	83	3	652
15	795	Normal	S_6	75	+10°	56	+10°	3.8	293	0.40	171	13.3	92	3	652
17	795	Normal	S_7	100	+10°	56	+10°	3.6	288	0.39	168	13.2	112	2	649
6/3-18	802	Low	S_7	100	+10°	56	+10°	3.6	282	0.38	165	13.4	339	-	655
16	798	Low	S_6	75	+10°	56	+10°	4.0	289	0.39	169	12.7	261	-	655
14	799	Low	S_5	50	+10°	56	+10°	3.6	326	0.44	191	14.2	309	-	653
12	798	LOw	S_4	25	+10°	56	+10°	3.6	328	0.45	192	15.0	253	-	658
6/4-7A	800	Normal	S_1	10	+10°	56	+10°	5.2	378	0.51	221	12.9	108	-	674
6/5-8	800	Low	S_2	10	+10°	48	+10°	3.6	259	0.35	151	15.2	549	-	652
8A	800	Low	S_1	10	+10°	48	+10°	3.6	298	0.41	174	15.7	97	-	649
7	800	Normal	S_2	10	+10°	48	+10°	5.0	318	0.43	186	13.8	124	-	650
7B	800	Normal	S_1	10	+10°	56	+10°	5.2	383	0.52	224	14.0	83	-	664
21	798	Normal	S_7	100	Horiz.	56	Horiz.	5.4	329	0.45	192	13.5	96	-	669
19	795	Normal	S_7	100	Horiz.	56	-15°	5.2	346	0.47	202	13.8	85	-	663
20	798	Low	S_7	100	Horiz.	56	-15°	3.5	271	0.37	158	15.7	160	-	658
22	795	Low	S_7	100	Horiz.	56	Horiz.	3.8	289	0.39	169	15.4	256	-	658
6/6-3B	802	Normal	S_1	10	+10°	56	+10°	5.4	416	0.57	243	13.5	111	-	663
17A	806	Normal	S_7	100	+10°	56	+10°	5.2	354	0.48	207	13.6	109	-	663
18A	802	Low	S_7	100	+10°	56	+10°	4.2	291	0.40	170	15.1	183	-	652
6/18-3C	803	Normal	S_1	10	+10°	56	+10°	5.4	385	0.52	225	13.6	14	-	663
6/19-18B	808	Normal	S_7	100	+10°	56	+12°	4.4	349	0.47	204	14.2	36	-	659
6/20-18C	808	Normal	S_7	100	+10°	56	+11°	4.6	346	0.47	202	14.0	21	-	663
6/24-18D	305	Low	S_7	100	+10°	32	+25°	4.6	349	0.47	204	14.9	12	-	569
2A	792	Normal	S_1	10	+10°	56	-10°	3.9	332	0.45	194	15.6	30	-	661
6/26-3D	785	Normal	S_1	10	+10°	56	+10°	4.8	346	0.47	202	14.4	22	-	664
18E	798	Low	S_7	100	+10°	56	+10°	3.7	280	0.38	164	15.3	52	-	659
23	565	Normal	S_1	10	+10°	48	+10°	5.3	350	0.48	205	14.3	10	-	646
6/27-24	565	Normal	S_1	10	+10°	40	+30°	5.0	404	0.55	236	13.1	17	--	623

(a) Firing Patterns:
S_1 - Normal Firing
S_2 - Staged Firing - Top Row Burners on Air Only
S_4 - Overfire Air Ports 25% Open
S_5 - Overfire Air Ports 50% Open
S_6 - Overfire Air Ports 75% Open
S_7 - Overfire Air Ports 100% Open

APPENDIX C

TABLE 4

SUMMARY OF OPERATING AND EMISSION DATA - COMANCHE, BOILER NO. 1

(350 MWe, Tangential, Pulverized Coal Fired)

Date and Run No. (1975)	Operating Conditions								Flue Gas Measurements							
			Firing Pattern						O_2	NO_x			CO_2	CO	HC	Temp.
			No. of Burners		Over Fire Air											
	Gross Load (MWe)	Excess Air Level	Firing Coal	Air Only	% Open	Tilt	Burner Nozzle Tilt	Secondary Air Reg. Aux/Coal (% Open)	%	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	Nanogram Per Joule	%	PPM (3% O_2, Dry)	PPM (3% O_2, Dry)	Kelvin
7/14-1	340	Normal	S_1-20	None	Closed	Horiz.	-14°	40/100	3.9	391	0.53	229	15.6	22	2	794
3	334	Normal	S_1-20	None	Closed	Horiz.	-26°	40/100	4.0	448	0.61	262	15.1	19	1	796
5	340	Normal	S_1-20	None	Closed	Horiz.	Horiz.	40/100	3.7	336	0.46	196	15.7	33	1	800
7	340	Normal	S_2-20	None	10%	Horiz.	-16°	37/100	3.8	373	0.51	218	15.8	28	1	800
7/15-9	335	Normal	S_3-20	None	25%	-15°	-17°	35/100	4.1	355	0.48	208	15.4	31	1	—
11	335	Normal	S_4-20	None	50%	-15°	-17°	30/100	4.2	306	0.42	179	15.4	28	1	—
13	333	Normal	S_5-20	None	75%	-15°	-17°	27.5/100	3.7	261	0.35	153	15.8	37	1	—
15	332	Normal	S_6-20	None	100%	-15°	-18°	26.5/100	3.5	266	0.36	156	15.8	48	1	—
7/16-2	332	Normal	S_1-20	None	Closed	-15°	-16°	38/100	3.8	404	0.55	236	15.9	31	0	796
4	331	Normal	S_1-20	None	Closed	-15°	-18°	40/100	4.0	417	0.57	244	15.8	27	0	805
17	331	Normal	S_3-20	None	25%	-15°	-26°	36/100	4.0	383	0.52	224	15.7	38	0	808
18	332	Normal	S_3-20	None	25%	-15°	Horiz.	36/100	4.0	308	0.42	180	15.5	98	0	—
7/17-6	335	Normal	S_1-20	None	Closed	-15°	-16°	38/100	3.7	405	0.55	237	15.6	35	0	800
7/18-20	322	Normal	S_3-20	None	25%	Horiz.	-17°	29/100	3.9	362	0.49	212	15.5	55	0	795
8	323	Normal	S_1-20	None	Closed	Horiz.	-20°	36/100	3.8	428	0.58	250	15.6	52	0	802
21	321	Normal	S_3-20	None	25%	Horiz.	-23°	33/100	3.9	364	0.50	213	15.2	50	0	803
19	322	Normal	S_3-20	None	25%	Horiz.	-4°	32/100	4.0	332	0.45	194	15.4	53	0	798
7/21-22	322	Normal	S_4-20	None	50%	Horiz.	Horiz.	26/100	4.0	280	0.38	164	15.5	169	0	785
23	321	Normal	S_4-20	None	50%	Horiz.	-15°	22/100	4.2	316	0.43	185	15.2	40	0	785
24	316	Normal	S_4-20	None	50%	Horiz.	-25°	22/100	4.4	326	0.44	191	15.0	42	0	773
7/22-25	322	Normal	S_4-20	None	50%	Horiz.	-15°	22/100	4.2	268	0.36	137	15.1	35	0	778
26	321	Normal	S_4-20	None	50%	Horiz.	-18°	24/100	4.1	284	0.39	166	15.5	25	0	785
7/23-27	321	Normal	S_4-20	None	50%	Horiz.	-20°	23/100	3.8	245	0.33	143	15.1	36	0	791
7/24-28	322	Normal	S_4-20	None	50%	Horiz.	-21°	22/100	3.8	259	0.35	151	15.6	38	0	794
7/25-29	321	Normal	S_4-20	None	50%	Horiz.	-19°	24/100	4.4	289	0.39	169	15.2	57	0	800
7/29-30	325	Normal	S_1-20	None	Closed	Horiz.	-20°	37/100	3.7	380	0.52	222	15.5	85	2	809
31	322	Normal	S_4-20	None	50%	Horiz.	-20°	27/100	3.9	271	0.37	158	15.8	112	2	808
7/30-32A	323	Normal	S_4-20	None	50%	Horiz.	-15°	26/100	3.9	273	0.37	160	15.2	96	2	800
32B	324	Normal	S_4-20	None	50%	Horiz.	-15°	26/100	3.9	275	0.37	161	15.7	70	2	—
33	323	Normal	S_1-20	None	Closed	Horiz.	-15°	37/100	3.9	389	0.53	227	15.8	77	2	—
8/1-34	330	Normal	S_4-20	None	50%	Horiz.	-7°	24/100	3.4	200	0.27	117	16.0	39	1	789

APPENDIX C

TABLE 5

SUMMARY OF OPERATING AND EMISSION DATA - BARRY, BOILER NO. 2

(130 MWe, Tangential, Pulverized Coal Fired)

	Operating Conditions									Flue Gas Measurements								
			Firing Pattern					Secondary Air Reg.		O_2	NO_x			CO_2	CO	HC	Temp.	Opacity
				Burners														
Date and Run No. (1975)	Gross Load (MWe)	Excess Air Level	Mills Off(a)	No. on Coal	No. on Air	OFA Ports % Open(b)	Burner Tilt	% Open Coal/Aux.	Fuel Fired	%	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	Nanogram Per Joule	%	PPM (3% O_2, Dry)	PPM (3% O_2, Dry)	Kelvin	%
2/12-1	131	Normal	S_1-None	16	0	5	-17	30/100	Alab. Coal	4.9	365	0.50	213	15.0	24	1	576	--
2	130	Normal	S_2-None	16	0	50	-17	30/100	Alab. Coal	4.8	294	0.40	172	14.7	25	1	583	--
3	128	Normal	S_3-None	16	0	100	-17	30/100	Alab. Coal	4.7	265	0.36	155	14.7	22	1	583	--
4	129	Low	S_3-None	16	0	100	-17	30/100	Alab. Coal	3.8	189	0.26	111	16.0	49	3	579	55-60
5	129	Low	S_2-None	16	0	50	-17	30/100	Alab. Coal	3.5	182	0.25	106	16.4	227	2	574	50-70
6	126	Low	S_1-None	16	0	5	-17	30/100	Alab. Coal	3.1	196	0.27	115	16.9	783	1	571	55-70
2/13-25	95	Normal	S -None	16	0	5	-2	30/100	Ill. Coal	7.3	452	0.61	264	11.7	22	2	569	50-60
7	93	Normal	S_2-None	16	0	50	-2	30/100	Ill. Coal	7.1	411	0.56	240	11.7	21	6	569	50-60
8	93	Low	S_2-None	16	0	50	-2	30/100	Ill. Coal	4.8	253	0.34	148	13.5	60	3	556	60-75
11	93	Normal	S_5-"A"	12	4	50	-2	30/100	Ill. Coal	6.8	272	0.37	159	11.9	22	4	566	60
12	95	Low	S_5-"A"	12	4	50	-2	30/100	Ill. Coal	4.3	192	0.26	112	14.6	48	3	555	60-70
9	94	Normal	S_4-"A"	12	4	5	-2	30/100	Ill. Coal	7.1	330	0.45	193	12.6	18	7	566	50-60
10	95	Low	S_4-"A"	12	4	5	-2	30/100	Ill. Coal	4.6	212	0.29	124	15.5	203	3	555	60-70
26	130	Normal	S_1-None	16	0	5	-2	30/100	Ill. Coal	5.4	345	0.47	202	15.0	22	2	582	60-75
2/19-21	130	Normal	S_1-"A"	12	0	5	-2	30/100	Kty.+.4 Gas	3.9	168	0.23	98	13.2	743	3	585	60
22	128	Normal	S_2-"A"	12	0	50	-2	30/100	Kty.+.4 Gas	4.6	184	0.25	108	12.5	30	2	586	55-70
23	132	Normal	S_3-"A"	12	0	100	+1	30/100	Kty.+.4 Gas	4.9	182	0.25	106	12.0	18	3	586	55-65
24	130	Low	S_3-"A"	12	0	100	+1	30/100	Kty.+.4 Gas	3.7	143	0.19	84	13.2	389	2	584	50-60
27	133	Normal	S_1-"C"	12	0	5	+1	30/100	Kty.+.4 Gas	4.5	206	0.28	120	13.2	210	6	586	50-60
28	130	Normal	S_2-"C"	12	0	50	+1	30/100	Kty.+.4 Gas	5.1	186	0.25	109	12.5	65	4	586	60
29	130	Low	S_3-"C"	12	0	100	+1	30/100	Kty.+.4 Gas	5.0	184	0.25	108	12.6	78	3	585	60
30	128	Normal	S_3-"C"	12	0	100	+1	30/100	Kty.+.4 Gas	4.9	190	0.26	111	12.6	47	3	587	60
2/20-17	131	Low	S_1-None	16	0	5	+1	30/100	Kty.+.2 Gas	4.9	218	0.30	127	13.9	41	6	587	70
18	128	Low	S_1-None	16	0	5	+1	30/100	Kty.+.2 Gas	4.2	198	0.27	116	14.3	547	2	580	75
19	132	Low	S_2-None	16	0	50	+1	30/100	Kty.+.2 Gas	4.8	212	0.29	124	13.9	137	2	586	70
20	134	Low	S_3-None	16	0	100	+1	30/100	Kty.+.2 Gas	4.6	191	0.26	112	14.0	143	2	585	--
15	58	Normal	S_1-ABCD	0	0	5	+9	30/100	Gas	9.2	122	0.17	71	7.2	10	10	538	--
16	56	Low	S_1-ABCD	0	0	5	+6	30/100	Gas	7.3	97	0.13	57	8.3	12	5	533	--
13	54	Normal	S_1-A,B	8	0	5	+9	20/50	Kty. Coal	8.8	284	0.39	166	10.8	28	6	537	80-100
14	55	Low	S_1-A,B	8	0	5	+9	20/50	Kty. Coal	6.9	254	0.35	149	11.7	26	7	535	65-80
2/21-31	133	Normal	S_1-None	16	0	5	+1	30/100	Kty. Coal	4.3	314	0.42	184	14.1	20	--	588	--
32	131	Normal	S_1-None	16	0	5	+20	30/100	Kty. Coal	4.0	320	0.44	187	13.0	70	--	587	--
33	135	Normal	S_1-None	16	0	5	-20	30/100	Kty. Coal	3.9	273	0.37	160	12.8	40	--	585	--
34	134	Normal	S_1-None	16	0	5	0	100/50	Kty. Coal	3.8	299	0.41	175	12.8	47	--	586	--
35	132	Low	S_2-None	16	0	50	0	100/50	Kty. Coal	4.0	233	0.32	136	13.3	56	--	549	55-70
37	128	Low	S_2-None	16	0	50	-20	100/50	Kty. Coal	4.0	218	0.30	127	13.5	32	--	587	--
36	130	Low	S_2-None	16	0	50	+20	100/50	Kty. Coal	4.1	274	0.37	160	13.3	103	4	590	--
38	126	Normal	S_2-None	16	0	50	0	30/100	Kty. Coal	4.7	243	0.33	142	12.7	28	3	588	--

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(a) Mills are designated "A" for the mill feeding the top row of burners through "D", the mill feeding the bottom row of burners.

(b) Overfire air "NO" ports are about 5% open for cooling, when in a "closed" position.

APPENDIX C

TABLE 6

SUMMARY OF OPERATING AND EMISSION DATA - MORGANTOWN STATION, BOILER NO. 1

(575 MWe, Pulverized Coal and/or Oil Tangentially Fired)

Date and Run No. (1975)	Operating Conditions									Flue Gas Measurements							
			Firing Pattern(a)							O_2	NO_x			CO_2	CO	HC	Temp.
	Gross Load (MWe)	Excess Air Level	Symbol	Mills on		No. of Oil Burners	Burner Tilt	Fuel Fired - % Coal/% Oil	% Stoich. Air to Active Burners(b)	%	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	Nanogram Per Joule	%	PPM (3% O_2, Dry)	PPM (3% O_2, Dry)	Kelvin
				Coal	Air												
3/14-1	576	Normal	S_1	A,C	None	21	-2°	22/78	125	4.4	458	0.62	268	13.8	21	2	--
2	576	Low	S_1	A,C	None	21	-2°	22/78	110	2.1	386	0.52	226	15.5	53	1	--
3	576	Normal	S_2	C,E	A	21	0°	22/78	102	4.6	375	0.51	219	13.3	16	1	--
4	575	Low	S_2	C,E	A	21	0°	22/78	94	3.3	310	0.42	181	13.8	39	1	--
5	576	Low	S_2	C,E	A	21	+13°	22/78	94	3.4	334	0.45	195	13.1	27	1	--
6	584	Low	S_2	C,E	A	21	-12°	22/78	94	3.1	314	0.43	184	13.0	18	1	--
3/18-7	576	Normal	S_1	A,B,C,D	None	18	0°	45/55	126	4.5	525	0.71	307	13.[illegible]	15	2	--
8	576	Normal	S_1	A,B,C,D	None	18	+15°	45/55	128	4.7	553	0.75	323	13.2	17	1	--
9	576	Normal	S_1	A,B,C,D	None	18	-15°	45/55	128	4.7	568	0.77	332	13.0	16	1	--
3/19-7A	576	Normal	S_1	A,B,C,D	None	17	0°	49/51	128	4.7	577	0.78	337	13.9	13	0	--
10	576	Low	S_1	A,B,C,D	None	17	0°	49/51	115	2.8	502	0.68	293	15.4	18	0	--
11	576	Normal	S_2	B,C,D,E	A	17	0°	49/51	101	4.5	465	0.63	272	13.8	14	0	--
12	576	Low	S_2	B,C,D,E	A	16	+1°	49/51	94	3.1	423	0.58	247	15.7	18	0	--
3/20-13	578	Normal	S_1	A,B,C,D,E	None	10	+1°	73/27	125	4.4	593	0.81	347	14.9	160	14	--
3/21-14	572	Low	S_1	A,B,C,D,E	None	10	+2°	72/28	119	3.4	511	0.69	299	13.9	25	2	--
15	572	Normal	S_2	B,C,D,E	A	10	+2°	74/26	102	4.7	403	0.55	236	14.4	20	1	623
17	570	Normal	S_1	A,B,C,D,E	None	2	+2°	93/7	129	4.9	552	0.75	323	14.0	21	1	624
18	572	Low	S_1	A,B,C,D,E	None	2	+2°	93/7	121	3.8	549	0.75	321	14.8	30	1	622
3/25-19	303	Low	S_2	None	A	16	0°	0/100	105	5.1	165	0.22	96	11.8	32	23	566
20	300	High	S_2	None	A	16	0°	0/100	99	4.2	149	0.20	87	13.1	63	34	--
21	300	High	S_2	B	A	14	0°	20/80	107	5.4	246	0.33	144	13.0	19	16	569
22	306	High	S_2	B,C	A	8	0°	50/50	107	5.4	300	0.40	175	13.8	57	12	569
25	301	High	S_1	A,B,C,D	None	0	0°	100/0	144	6.5	544	0.74	318	13.0	20	12	569
26	314	Low	S_1	A,B,C,D	None	0	0°	100/0	142	6.3	515	0.70	301	13.3	20	9	574
3/26-21A	298	Normal	S_1	A	None	16	0°	5/95	138	5.9	247	0.34	144	12.2	19	27	569
22A	300	Normal	S_1	A,D,E	None	8	0°	43/57	148	6.9	408	0.55	239	11.8	20	24	630
24	300	Normal	S_1	A,D,E	None	6	0°	62/38	147	6.8	460	0.63	269	12.0	20	17	580

(a) Firing Pattern: S_1 - Normal Firing, S_2 - Overfire Air Staged Firing; 5 Mills (A at top to E on bottom).
(b) Based on simplifying assumption that air flows to each burner are equal.

APPENDIX C

TABLE 7

SUMMARY OF OPERATING AND EMISSION DATA - MERCER, BOILER NO. 1

(315 MWe, Horizontally Opposed, Pulverized Coal Fired)

Date and Run No. (1975-1976)	Operating Conditions						Flue Gas Measurements								
							O_2	NO_x			CO_2	CO	HC	Temp.	Opacity
	Gross Load (MWe)	Excess Air Level	Firing Pattern(a)	Secondary Air Registers(b) Top	Mid	Bot	%	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	Nanogram Per Joule	%	PPM (3% O_2, Dry)	PPM (3% O_2, Dry)	Kelvin	%
12/3-1	296	Normal	S_1-Normal	80%	80%	80%	3.9	1383	1.88	808	14.6	22	1	705	--
2	290	Low	S_1-Normal	80%	80%	80%	1.9	1147	1.56	671	17.3	32	3	689	22
3	290	Normal	S_2-Biased	80%	80%	80%	3.2	1237	1.68	723	16.0	21	5	705	15
4	290	Low	S_2-Biased	80%	80%	80%	1.4	922	1.25	539	17.7	131	3	700	15
12/4-5	288	Normal	S_1-Normal	80%	50%(c)	50%(c)	3.9	1439	1.96	841	15.4	21	5	711	30
6	285	Low	S_1-Normal	80%	50%(c)	50%(c)	2.0	1038	1.41	607	17.0	25	3	711	20
7	283	Normal	S_2-Biased	80%	50%(c)	50%(c)	3.9	1164	1.58	681	15.4	24	3	700	30
8	284	Low	S_2-Biased	80%	50%(c)	50%(c)	1.8	876	1.19	512	17.1	61	2	691	20
1A	290	Normal	S_1-Normal	80%	80%	80%	4.1	1319	1.79	771	14.6	15	4	705	35
12/5-1B	280	Normal	S_1-Normal	80%	80%	80%	4.9	1256	1.71	735	14.0	17	2	705	30
1C	291	Normal	S_1-Normal	80%	80%	80%	3.9	1321	1.80	773	14.4	19	3	700	30
1D	292	Normal	S_1-Normal	80%	80%	80%	4.0	1302	1.77	761	15.0	18	3	703	--
12/8-23	150	Low	S_4-Top Off	0%	80%	80%	5.0	778	1.06	455	14.1	16	3	641	--
24	151	Normal	S_3-Top Off	0%	80%	80%	6.6	906	1.23	530	12.1	15	3	641	--
26	152	Low	S_3-Staged	80%	80%	80%	4.3	341	0.46	199	14.0	27	1	641	--
25	152	Normal	S_3-Staged	80%	80%	80%	8.2	771	1.05	451	10.6	22	2	664	--
29	155	Normal	S_3-Staged	50%	80%	80%	8.0	840	1.14	491	10.8	16	2	658	--
30	150	Low	S_3-Staged	50%	80%	80%	4.5	482	0.66	282	14.2	18	1	658	--
12/9-10	219	Low	S_3-Staged	80%	80%	80%	3.6	386	0.52	226	15.0	218	1	658	--
9	218	Normal	S_3-Staged	80%	80%	80%	6.8	769	1.05	449	11.6	20	2	673	--
27	216	Normal	S_3-Staged	50%	80%	80%	6.6	856	1.16	501	11.6	17	2	675	--
28	212	Low	S_3-Staged	50%	80%	80%	3.1	364	0.50	213	15.0	338	1	658	--
20	210	Low	S_3-Staged	15%	80%	80%	2.3	612	0.83	358	15.8	69	0	650	--
19	211	Normal	S_3-Staged	15%	80%	80%	6.3	1016	1.38	594	11.8	26	2	675	--
12/10-11	238	Normal	S_1-Normal	80%	80%	80%	5.9	1136	1.54	664	12.6	16	4	700	--
12	232	Low	S_1-Normal	80%	80%	80%	3.2	1019	1.39	596	15.0	19	3	678	--
22	226	Low	S_4-Top Off	0%	80%	80%	3.2	936	1.27	547	14.4	21	4	680	--
12/11-23A	165	Low	S_4-Top Off	0%	80%	80%	4.0	714	0.97	417	15.3	17	1	630	--
26A	161	Low	S_3-Staged	80%	80%	80%	4.2	362	0.49	212	14.3	43	1	633	--
25A	162	Normal	S_3-Staged	80%	80%	80%	7.0	689	0.94	403	11.3	33	3	642	--
12/12-17	236	Normal	S_1-Normal	80%	50%	50%	5.7	1137	1.55	665	12.3	12	4	683	--
18	232	Low	S_1-Normal	80%	50%	50%	3.5	1130	1.54	661	14.4	12	2	672	--
10A	211	Low	S_3-Staged	80%	80%	80%	3.3	327	0.44	191	15.6	264	1	664	--
1/20-4A(d)	265	Low/Normal	S_2/S_1	80%	80%	80%	2.6	1018	1.38	595	15.8	48	2	682	15
1/21-4B(d)	268	Low/Normal	S_2/S_1	80%	80%	80%	2.4	1001	1.36	585	16.8	18	3	686	--
1/22-4C(d)	269	Low/Normal	S_2/S_1	80%	80%	80%	2.8	997	1.36	583	16.3	24	2	684	--

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(a) S_2-Biased Firing: top row of burners fuel-lean with middle and bottom burners fuel-rich; S_3-Staged Firing: top row of burners on air only; S_4-Baseline at Low Load: top row of burners air and coal off.

(b) Secondary air register settings are Fire 2, 80% open, Fire 1, 50% open for low load firing; Fire Ignite (F_{Ign}), 15% open.

(c) Reheat furnace - 50% and superheat furnace 80% open, respectfully.

(d) Reheat furnace operated under low excess air, biased firing (S_2) and superheat furnace operated under baseline operations (S_1).

APPENDIX C

TABLE 8

SUMMARY OF OPERATING AND EMISSION DATA - MORGANTOWN STATION, GAS TURBINE NO. 3

(50 MWe Oil Fired)

	Operating Conditions				Flue Gas Measurements								
					O_2	NO_x				CO_2	CO	HC	Temp.
Date and Run No. 1975	Gross Load MWe	Fuel Flow l/sec.	Ambient Air Temp. Kelvin	Compressor Inlet Temp. Kelvin	%	PPM (15% O_2 Dry)	PPM (3% O_2 Dry)	Pounds Per 10^6 BTU	Nanogr. Per Joule	%	PPM (3% O_2 Dry)	PPM (3% O_2 Dry)	Kelvin
4/1-1	10	2.08	290	290	17.9	32	247	0.33	144	2.1	244	73	601
2	25	2.96	290	290	17.3	108	322	0.43	188	2.5	89	33	611
3	48	4.67	290	291	15.2	125	376	0.50	220	4.0	12	17	758
4	54	5.11	290	293	14.7	133	398	0.53	233	4.3	11	16	800

APPENDIX D

Coal Analyses

Representative coal samples were taken for each major test under baseline and "low NO_x" operating conditions. The samples were submitted to the Exxon Research and Engineering Company's Coal Analysis Laboratory at Baytown, Texas for analysis. Ultimate analysis determinations, which were of most importance to the study, were made on all samples as indicated in the following tables for each boiler tested. Proximate analyses information are also tabulated, where available. Ash fusion temperature determinations under reducing and oxidizing conditions and analyses for critical coal ash elements were obtained on coal samples taken during certain important tests in an attempt to shed more light on potential slagging or fouling side effects of "low NO_x" firing techniques.

All coal analyses data, which were used for making various calculations in this report, are tabulated in Tables 1-7 of Appendix D.

APPENDIX D

TABLE 1

COAL ANALYSES

TENNESSEE VALLEY AUTHORITY
WIDOWS CREEK STATION - BOILER NO. 3

Test No.	1B	1C	12C-12D
Laboratory No.	96256	96257	96258
Sample	Raw Coal	Raw Coal	Raw Coal
Date	10/7/74	10/8/74	10/15/74
Test Conditions	Base	Base	Low NO_x
Proximate Analysis			
Moisture (as rec'd.)	8.40	10.18	13.67
Ash	14.64	18.27	12.30
Volatiles	30.18	29.41	32.35
Fixed Carbon	46.79	42.14	41.68
Sulfur	2.77	4.16	3.71
Btu/lb.	11,281	10,258	10,622
Hardgrove Grindability	65.9	73.1	63.8
Ultimate Analysis-Dry Basis			
C - %	68.58	63.43	68.0
H - %	4.46	4.29	4.63
S - %	3.02	4.63	4.30
N - %	1.21	1.21	1.20
Cl - %	----	----	----
O - %	6.75	6.10	7.63
Ash - %	15.98	20.34	14.25
Btu/lb. - %	12,316	11,420	12,304
Ash Elements			
P_2O_5 - %	0.40	0.40	0.40
SiO_2 - %	49.99	44.67	42.35
Fe_2O_3 - %	16.67	23.08	23.53
Al_2O_3 - %	22.52	17.37	20.09
TiO_2 - %	0.96	0.80	0.93
CaO - %	2.81	5.47	6.08
MgO - %	1.02	1.06	0.80
SO_3 - %	2.06	3.06	3.22
K_2O - %	2.21	2.34	1.69
Na_2O - %	0.25	0.29	0.33
Total - %	98.89	98.54	99.42
Ash Fusion Temperature			
Reducing - I.D.	2100	1950	2010
- H=W	2150	1990	2050
- H=1/2W	2180	2000	2075
- Fluid	2475	2030	2125
Oxidizing - I.D.	2475	2160	2175
- H=W	2485	2350	2400
- H=1/2W	2510	2400	2420
- Fluid	2525	2425	2450

APPENDIX D

TABLE 2

COAL ANALYSES

SOUTHERN ELECTRIC GENERATING COMPANY
E. C. GASTON STATION - BOILERS No.'s 1 AND 2

Test No.	28A, 28B	29	30	26	27A, 27B
Laboratory No.	96284	96288	96292	96274	96279
Sample	Raw Coal	Raw Coal	Raw Coal	Raw Coal	Raw Coal
Date	1/22/75	1/23/75	1/29/75	1/17/75	1/20/75
Test Conditions	Base	Base	Base	Low NO_x	Low NO_x
Boiler No.	2	2	2	1	1
Proximate Analysis					
Moisture (as rec'd.)	6.04	6.61	7.82	6.35	5.29
Ash	15.00	16.06	13.28	12.12	9.84
Volatiles	27.66	29.71	30.55	33.97	----
Fixed Carbon	51.30	47.62	48.35	47.56	----
Sulfur	1.38	1.22	1.59	3.11	1.25
Btu/lb.	11,690	11,461	11,398	11,752	11,632
Hardgrove Grindability	----	63.0	58.0	59.5	59.5
Ultimate Analysis-Dry Basis					
C - %	69.51	69.12	69.89	70.13	69.29
H - %	4.57	4.63	4.54	4.86	4.64
S - %	1.47	1.31	1.73	3.33	1.32
N - %	1.61	1.42	1.42	1.51	1.58
Cl - %	----	----	----	----	----
O - %	15.96	6.33	8.02	7.24	12.77
Ash - %	----	17.20	14.40	12.94	10.39
Btu/lb.		12,272	----	12,549	12,282
Ash Elements					
P_2O_5 - %	0.62	0.37	0.42	0.31	0.83
SiO_2 - %	50.46	53.00	53.32	47.21	53.65
Fe_2O_3 - %	8.33	10.16	11.77	21.53	8.10
Al_2O_3 - %	29.23	26.34	23.35	22.38	27.06
TiO_2 - %	1.52	1.20	1.20	1.11	1.29
CaO_2 - %	3.30	2.18	3.10	2.20	2.95
MgO - %	1.29	1.50	1.16	1.09	1.36
SO_3 - %	1.97	2.12	3.17	2.57	1.68
K_2O - %	1.70	3.18	2.00	1.80	2.55
Na_2O - %	0.59	0.47	0.35	0.37	0.48
Total - %	99.01	100.52	99.83	100.57	99.95
Ash Fusion Temperature					
Reducing - I.D.	2425	2275	2075	2000	2475
- H=W	2575	2540	2320	2065	2540
- H=1/2W	2620	2570	2375	2085	2575
- Fluid	2680	2650	2550	2110	2675
Oxidizing - I.D.	2625	2550	2425	2425	2700+
- H=W	2700+	2625	2575	2530	2700+
- H=1/2W	2700+	2650	2610	2560	2700+
- Fluid	2700+	2690	2625	2580	2700+

APPENDIX D

TABLE 3

COAL ANALYSES

ALABAMA POWER COMPANY
BARRY STATION - BOILER NO. 2

Test No.	1-6	7-12, 25, 26	21-24, 27-30	13-20	31-38
Laboratory No.	96295	96296	96297	96298	96299
Sample	Raw Coal	Raw Coal	Raw Coal	Raw Coal	Raw Coal
Source	Alabama	Ohio/Ky.	Rockport, Ky.	Rockport, Ky.	Rockport, Ky.
Date	2/12/75	2/13/75	2/19/75	2/20/75	2/21/75
Proximate Analysis					
Moisture (as rec'd.)	5.51	6.96	10.11	12.30	10.15
Ash (as rec'd.)	13.22	10.79	12.03	11.85	11.01
Volatiles (as rec'd.)	28.38	34.62	31.81	30.19	32.49
Fixed Carbon (as rec'd.)	52.89	47.63	46.05	45.66	46.35
Sulfur (as rec'd.)	2.00	3.41	3.11	2.57	2.93
Btu/lb.	12,237	11,802	11,081	11,862	11,389
Hardgrove Grindability	----	55.2	64.5	57.3	56.6
Ultimate Analysis-Dry Basis					
C - %	71.32	70.65	68.37	69.13	70.51
H - %	4.81	4.95	4.93	4.76	4.79
S - %	2.12	3.67	3.46	2.93	3.26
N - %	1.59	1.56	1.48	1.55	1.45
O - %	6.17	7.57	8.37	8.12	7.73
Ash - %	13.99	11.60	13.39	13.51	12.26
Btu/lb.	12,950	12,685	12,327	12,328	12,675
Ash Elements					
P_2O_5 %	0.78	0.30	0.30	0.28	0.23
SiO_2 %	45.96	43.57	46.49	47.60	45.35
Fe_2O_3 %	16.25	23.46	24.26	24.56	21.67
Al_2O_3 %	27.45	18.83	20.30	20.57	18.04
TiO_2 %	1.45	0.86	0.93	0.91	0.87
CaO %	1.91	4.76	2.08	1.68	5.13
MgO %	1.23	0.87	1.06	1.00	0.99
SO_3 %	1.02	4.10	1.37	0.74	5.07
K_2O %	2.51	1.88	2.28	2.96	2.27
Na_2O %	0.40	0.47	0.24	0.17	0.44
Total	98.94	99.10	99.31	100.47	100.07
Ash Fusion Temperatures					
Reducing - I.D.	1950	2000	2010	2000	1970
- H=W	2350	2340	2050	2065	2025
- H=1/2W	2400	2410	2065	2090	2040
- Fluid	2570	2450	2100	2110	2065
Oxidizing - I.D.	2660	2360	2500	2510	2350
- H=W	2700+	2440	2550	2575	2410
- H=1/2W	2700+	2520	2590	2600	2450
- Fluid	2700+	2580	2610	2625	2520

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TABLE 4

COAL ANALYSES

POTOMAC ELECTRIC COMPANY
MORGANTOWN STATION - BOILER NO. 1

Test No.	1-6	-	21A, 22A, 24	-
Laboratory No.	96300	96301	96302	96303
Sample	Raw Coal	Raw Coal	Raw Coal	Raw Coal
Source	West Va.	Comp. F-334	--	Comp. F-335
Date	3/14/75	3/19-3/25/75	3/26/75	3/19-31/75
Proximate Analysis				
Moisture (as rec'd.)	7.05	9.14	9.54	8.29
Ash (rec'd.)	20.40	12.92	13.88	15.24
Volatiles (as rec'd.)	20.54	20.77	21.30	21.50
Fixed Carbon (as rec'd.)	52.00	57.17	55.28	54.97
Sulfur (as rec'd.)	1.92	2.05	1.94	1.41
Btu/lb.	10,792	11,630	11,296	11,428
Hardgrove Grindability	100.3	104.6	96.7	106.0
Ultimate Analysis-Dry Basis				
C %	66.17	73.28	71.58	71.59
H %	3.99	4.06	4.27	4.18
S %	2.06	2.26	2.14	1.53
N %	1.20	1.28	1.33	1.33
O %	4.63	4.90	5.33	4.75
Ash %	21.95	14.22	15.35	16.62
Btu/lb.	11,611	12,800	12,488	12,461
Ash Elements				
P_2O_5 %	0.34	0.50	0.47	0.35
SiO_2 %	53.06	46.65	47.13	50.18
Fe_2O_3 %	12.78	19.20	18.65	14.73
Al_2O_3 %	25.89	26.41	25.32	27.47
TiO_2 %	1.26	1.32	1.19	1.32
CaO %	1.19	1.89	2.18	1.87
MgO %	1.08	0.75	0.79	0.89
SO_3 %	1.05	1.50	1.94	1.10
K_2O %	2.19	1.65	2.08	2.46
Na_2O %	0.13	0.19	0.16	0.18
Total	98.96	100.05	99.91	100.56
Ash Fusion Temperatures				
Reducing - I.D.	2400	2180	2150	2440
- H=W	2475	2350	2340	2510
- H=1/2W	2510	2430	2480	2545
- Fluid	2640	2570	2625	2700+
Oxidizing - I.D.	2625	2570	2535	2660
- H=W	2690	2625	2590	2700+
- H=1/2W	2700+	2640	2610	2700+
- Fluid	2700+	2660	2630	2700+

APPENDIX D

TABLE 5

COAL ANALYSES

SALT RIVER PROJECT
NAVAJO STATION - BOILER NO. 2

Test No.	3B, 18B	18B	2A	3D, 18E
Laboratory No.	96304	96305	96306	96307
Date	6/18,19/75	6/20/75	6/24/75	6/26/75
Sample	Raw Coal	Raw Coal	Raw Coal	Raw Coal
Conditions	Base and Low NO_x	Low NO_x	Base	Base and Low NO_x
Location of Sample	Feeders	Feeders	Feeders	Feeders
Proximate Analysis				
Moisture (as rec'd.)	13.27	13.54	12.45	12.81
Ash	11.49	6.62	5.94	6.04
Volatiles	35.65	36.89	38.43	37.96
Fixed Carbon	39.59	42.95	43.18	43.19
Sulfur	0.48	0.48	0.42	0.48
Btu/lb.	10,210	10,780	11,068	10,954
Hardgrove Grindability	40.1	42.3	40.9	39.4
Ultimate Analysis				
C - % Dry	66.78	71.60	72.42	72.18
H - % Dry	4.79	5.06	5.15	5.16
S - % Dry	0.56	0.55	0.48	0.55
N - % Dry	1.39	1.38	1.43	1.38
O - % Dry	13.24	13.75	13.73	13.79
Ash - % Dry	13.25	7.65	6.78	6.93
Btu/lb. - % Dry	11,772	12,469	12,642	12,563
Ash Elements				
P_2O_5	0.32	0.50	0.61	0.40
SiO_2	52.48	43.43	41.54	47.37
Fe_2O_3	3.96	5.36	6.62	5.66
Al_2O_3	23.34	19.46	18.18	17.23
TiO_2	0.97	0.85	0.95	0.91
CaO	6.24	11.65	11.98	9.34
MgO	1.36	1.83	2.02	1.59
SO_3	6.82	14.05	14.80	13.37
K_2O	0.33	0.27	0.17	0.27
Na_2O	1.98	3.58	4.29	3.77
Total	97.0	100.99	101.17	99.91
Ash Fusion Temperatures				
Reducing - I.D.	2330	2075	2050	2075
- H=W	2350	2125	2160	2150
- H=1/2W	2390	2180	2190	2180
- Fluid	2550	2225	2210	2225
Oxidizing - I.D.	2370	2200	2175	2175
- H=W	2400	2275	2225	2250
- H=1/2W	2500	2300	2300	2275
- Fluid	2550	2400	2340	2360

APPENDIX D

TABLE 6

COAL ANALYSES

PUBLIC SERVICE OF COLORADO
COMANCHE STATION
BOILER NO. 1
PUEBLO, COLORADO

Test No.	30, 33	27A, 27B	34, 35
Laboratory No.	96353	96351	96356
Sample	Raw Coal	Raw Coal	Raw Coal
Date	7/29/75	7/23/75	8/1/75
Conditions	Base	Low NO_x	Low NO_x
Proximate Analysis			
Moisture (as rec'd.)	31.86	31.57	31.54
Ash	5.36	5.43	5.62
Volatiles	29.21	28.94	30.05
Fixed Carbon	33.57	34.06	32.79
Sulfur	0.42	0.32	0.42
Btu/lb.	8,094	8,123	8,115
Hardgrove Grindability	52.3	50.2	49.4
Ultimate Analysis			
C - % Dry	69.24	69.06	69.08
H - % Dry	4.85	4.79	4.79
S - % Dry	0.61	0.46	0.61
N - % Dry	0.99	0.96	1.06
Cl - % Dry	----	----	----
O - % Dry	16.45	16.80	16.25
Ash - % Dry	7.86	7.93	8.21
Btu/lb. - Dry	11,879	11,871	11,854
Ash Elements			
P_2O_5	1.06	1.38	1.04
SiO_2	31.67	34.21	33.12
Fe_2O_3	4.97	4.61	5.03
Al_2O_3	18.75	18.87	16.28
TiO_2	1.20	1.28	1.48
CaO	21.52	20.57	21.36
MgO	3.67	3.57	3.75
SO_3	15.15	13.63	15.86
K_2O	0.38	0.37	0.36
Na_2O	1.43	1.51	1.12
Total	99.80	100.00	99.40
Ash Fusion Temperatures			
Reducing - I.D.	2125	2085	2075
- H=W	2150	2180	2140
- H=1/2W	2170	2200	2160
- Fluid	2180	2210	2175
Oxidizing - I.D.	2140	2100	2090
- H=W	2165	2160	2120
- H=1/2W	2170	2170	2130
- Fluid	2175	2200	2150

APPENDIX D

TABLE 7

COAL ANALYSES

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
MERCER STATION, BOILER NO. 1

Test No.	1 & 2	3 & 4	5 & 6
Laboratory No.	96390		96392
Sample	Raw Coal	Raw Coal	Raw Coal
Date	1/20/76	1/21/76	1/22/76
Test Conditions	← Base & Low NO_x →		
Proximate Analysis			
Moisture (as rec'd.)	6.02	6.64	6.31
Ash	9.57	9.23	11.00
Volatiles	29.17	29.74	26.82
Fixed Carbon	55.25	54.38	55.87
Sulfur	1.19	1.14	1.07
Btu/lb.	12,987	12,977	12,526
Hardgrove Grindability	63.8	61.6	67.3
Ultimate Analysis-Dry Basis			
C - %	77.21	77.47	76.34
H - %	4.85	4.89	4.66
S - %	1.27	1.21	1.13
N - %	1.53	1.54	1.49
Cl - %	----	----	----
O - %	4.95	5.01	4.65
Ash - %	10.18	9.88	11.73
Btu/lb. - %	13,819	13,900	13,369
Ash Elements			
P_2O_5 - %	0.52	0.54	0.24
SiO_2 - %	45.99	44.70	50.79
Fe_2O_3 - %	14.06	15.49	11.54
Al_2O_3 - %	27.60	27.69	26.62
TiO_2 - %	1.25	1.19	1.17
CaO - %	2.75	2.38	1.77
MgO - %	1.03	1.08	1.56
SO_3 - %	2.85	2.63	2.03
K_2O - %	1.96	1.97	3.07
Na_2O - %	0.26	0.24	0.38
Total - %	98.87	97.92	99.16
Ash Fusion Temperature			
Reducing - I.D.	2180	2180	2100
- H=W	2440	2450	2415
- H=1/2W	2475	2480	2465
- Fluid	2525	2510	2575
Oxidizing - I.D.	2540	2560	2525
- H=W	2625	2630	2625
- H=1/2W	2640	2640	2660
- Fluid	2685	2675	2700

APPENDIX E

EXXON MOBILE ANALYTICAL VAN SAMPLING SYSTEM

Design of Mobile Sampling and Analytical System

Meeting the objectives of our field program of measuring NO_x and related products of combustion emitted from a variety of power boilers required a versatile, transportable sampling and analytical train. Such a system had to be self-contained, mobile, and include provisions for wet chemical analysis of grab samples. Minimum set-up time was another requirement for the sampling and analytical system, which had to be installed at the actual sampling site to reduce the possibility of changes in the flue gas composition. Ideally, the instruments should have been located at the sampling point, but since this location was frequently inaccessible and was usually unsheltered, some compromise had to be made. Other requirements for the instruments for the measurement of the concentration of the flue gas components were easy calibration, maintenance-free and repeatable operation, and the ability to monitor gas compositions continuously. The last requirement is of extreme importance in a field program, where directional effects of operating changes must be assessed immediately.

Finally, the instrumental methods had to be compared against wet chemical methods of analysis, as needed, to validate the accuracy of the sampling system and continuous monitoring instrumentation.

Sampling System

The objective of obtaining data from coal, as well as oil and gas fired boilers required the development of an elaborate sampling system. Consideration of the solubility of NO_2 in water, the presence of oxides of sulfur, and the high concentration of particulates in the combustion gases were taken into account in the design of the sampling system. The sampling system was designed with adequate flexibility to allow gas sampling from different size boilers or other stationary combustion equipment. It could handle flue gases with heavy particulate loading from coal fired units, as well as light particulate loading from oil fired units. The sampling assembly was a dry-type system with appropriate particulate filters, pumps, and a refrigeration unit to cool the samples to a 35°F dew point before analysis.

The sampling points for flue gas components were usually located in the duct-work between the economizer and the air heater. This was done to provide reasonably homogeneous gas samples at the temperatures to which the probes could be subjected, and to avoid dilution of the samples by leakage in the air heaters of the boilers tested. In this part of the duct-work, temperatures usually ranged between 550°F and 800°F, and gas velocities were between 30 and 80 feet per second.

The variability of ducting between different boilers required the design of adjustable sampling probes. These probes were designed with interchangeable gas sampling tubes. Since we sampled from "equal areas" in ducts of different sizes, the probes were assembled on location for the particular duct. A special pitot tube and a thermocouple were located at the midpoint of each probe with a sampling tube. The remaining two gas sampling tubes were then assembled and the entire probe was ready to be inserted into the duct. Each probe was fitted with a quick disconnect as a mounting assembly for easy insertion into the boiler. All pieces of the sampling equipment between the van and the probes were of the quick-disconnect type for ease of assembly and assurance of a leak-proof connection at all intermediate points. Figure E-1 shows a schematic diagram of the sampling and analytical system.

In running field tests, the gas samples were withdrawn from the boiler under vacuum through stainless steel probes to heated paper filters where the particulate matter was removed. These paper filters were maintained at 300-500°F. The gases were then passed through rotameters, which were followed by a packed glass wool column for SO_3 removal. Initially, the gas temperatures were kept as high as possible to minimize condensation in the particulate filters. After leaving the packed column at 250-300°F, the gas samples passed at temperatures above the dew-point through heated Teflon lines to the vacuum/pressure pumps. The sample was then split with a portion at 120°F sent to the NO_2 instrument and the balance of the stream refrigerated to a 35°F dew-point before being sent to the van for analysis. Usually, the van was located 100 to 200 feet from this point and the gas stream flowed through Teflon lines throughout this distance.

The sampling system performed well during the test program, however, some difficulties were encountered with the vacuum pressure pumps. The pumps originally acquired for our sampling system were stainless steel bellows pumps. These pumps were manufactured with a clearance volume for slugging liquid entrainment. After about 40 hours of use the pumps began to leak and inspection revealed that the bellows became deformed and perforated with pinholes. The probable cause of failure was condensate remaining in the pump during the compression stroke deforming the bellows. The manufacturer (Metal Bellows Corp.) supplied replacement sets of pumps and we revised the sampling system in an attempt to overcome the problem. Water knockouts were incorporated before the pumps and the pumps were mounted upside down to facilitate draining of liquids that condensed during shutdown. This procedure did not eliminate the problem and new Teflon faced neoprene diaphragm pumps (Diapumps) had to be installed. These proved to be satisfactory in use for the remainder of the field test program.

Another problem of air leaking into the lines was found to be due to the flexible lines. While these lines were designed for high pressures and temperatures, their flexibility was not sufficient for our purpose. After severe bends, necessitated by probe locations, leaks would develop when the lines were heated to high temperatures. We are currently experimenting with a new design which eliminates the protective wire braid from the line on a replacement basis. Preliminary evaluation shows that this type of line is superior to the old one. Also, pressure-testing all lines at each boiler in future work will be required to correct this problem.

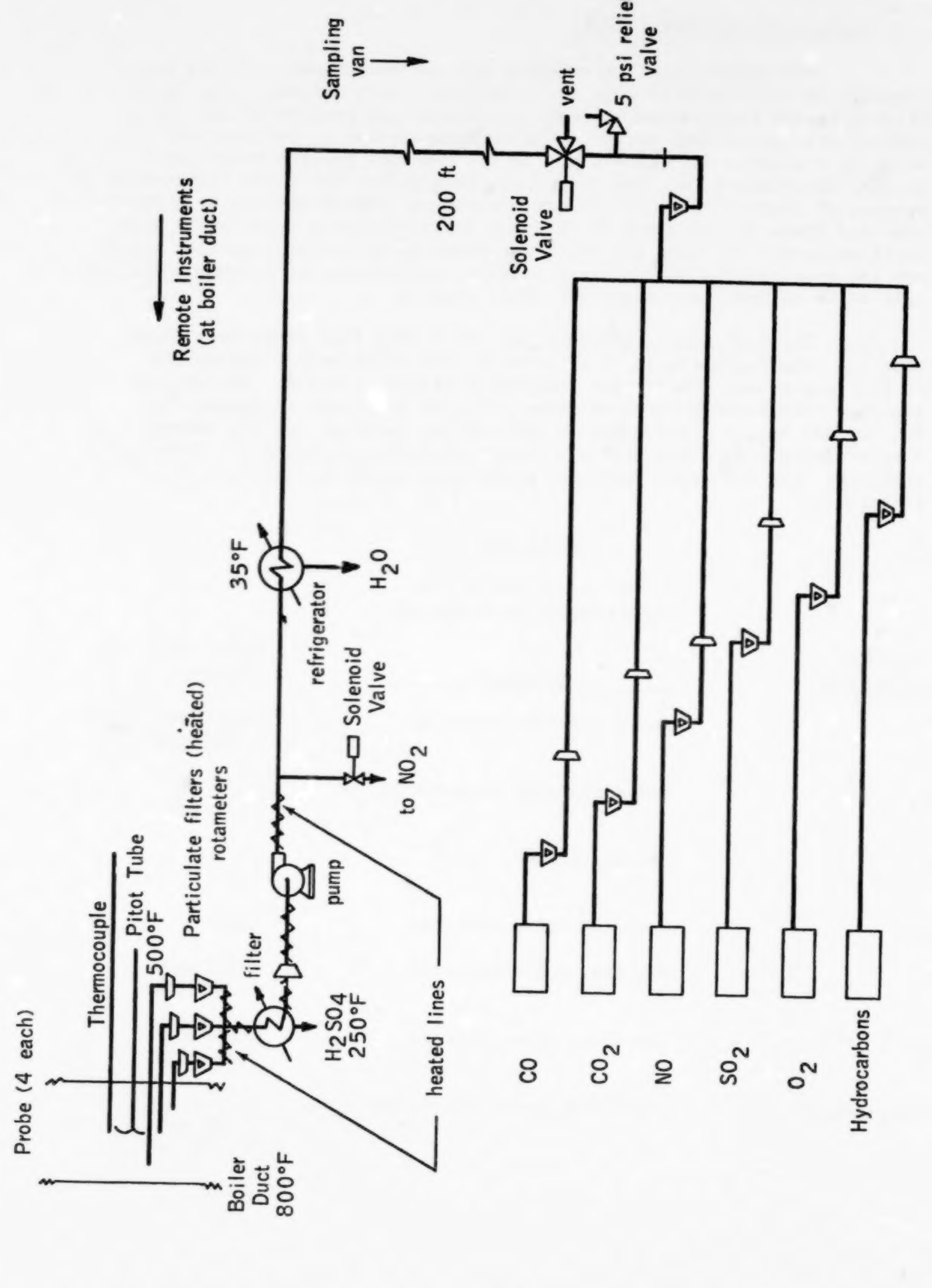
Probe (4 each)
Thermocouple
Pitot Tube
500°F
Particulate filters (heated)
rotameters
filter
pump
H_2SO_4
250°F
heated lines
Boiler
Duct
800°F
Solenoid
Valve
to NO_2
refrigerator
35°F
H_2O
Remote Instruments
(at boiler duct)
200 ft
Solenoid
Valve
Sampling
van
vent
5 psi relief
valve
CO
CO_2
NO
SO_2
O_2
Hydrocarbons

FIGURE E-1 EXXON RESEARCH TRANSPORTABLE SAMPLING AND ANALYTICAL SYSTEM

Analytical Instrument Train

The selection of instruments for the measurement of flue gas composition was complicated by the relatively short delivery time necessitated by the requirement to begin the field test program in the early part of the contractual period. The instruments had to be installed and wired in a console and checked out before the test program could begin. Beckman Instruments Inc. was chosen as the supplier for these instruments because of their ability to deliver monitoring instrumentation in a short time and Exxon Research and Engineering Company's prior familiarity with their analyzers in other air pollutant measurement trains. Another reason was the availability of the field service organization of Beckman which was felt to be an important asset for field studies.

The instruments selected for monitoring flue gases were those that had been demonstrated to be accurate and relatively trouble-free in previously used exhaust gas analytical trains at Exxon. Our van was equipped with Beckman non-dispersive infrared analyzers to measure NO, CO, CO_2 and SO_2, a non-dispersive ultraviolet analyzer for NO_2 measurement, a polarographic O_2 analyzer and a flame ionization detector for hydrocarbon analysis. The measuring ranges of these continuous monitors are listed in Table E-1.

TABLE E-1

Continuous Analytical Instruments in Exxon Van

Beckman Instruments	Technique	Measuring Range
NO	Non-dispersive infrared	0-400 ppm 0-2000 ppm
NO_2	Non-dispersive ultraviolet	0-100 ppm 0-400 ppm
O_2	Polarographic	0-5% 0-25%
CO_2	Non-dispersive infrared	0-20%
CO	Non-dispersive infrared	0-200 ppm 0-1000 ppm
SO_2	Non-dispersive infrared	0-600 ppm 0-3000 ppm
Hydrocarbons	Flame ionization detection	0-10 ppm 0-100 ppm 0-1000 ppm

The instruments were housed in a console which was shock-mounted inside the van. All connections to the console were made beneath the floor to prevent a tripping hazard. Separate raceways for piping and electric wires terminated in the base of the cabinet. Each analyzer was connected in parallel to the sample and calibration gas lines to insure that each analyzer would be operated independently of the others.

In the original design of the sampling-analytical train and during its construction, sufficient flexibility was engineered into our system to allow additional analyzers to be installed, and for modifications and special sample handling techniques to be incorporated. In addition to analytical instrumentation for continuously measuring all of the major flue gas components including NO, NO_2, CO, CO_2, O_2 and hydrocarbons (with an instrument added later to measure SO_2), the temperature and velocity of the gases in the duct could also be measured. A novel programmable sample timer was installed to allow any sample cycle to be simply dialed into the equipment. Normally, measurements from four different locations within the ducts could be made in eight minutes. After steady state conditions in the boiler had been established, the sampling time of 32 minutes per test allowed 4 repeats of each location assuring that reproducible data were obtained. The programmable sample timer proved to be very useful when monitoring operations at very low excess air levels, because the most sensitive areas had to be monitored more frequently.

Separate calibration gas cylinders in appropriate concentrations with N_2 carrier gas for each analyzer were installed in the van. Each cylinder was equipped with a regulator, safety relief valve, excess flow check valve and other necessary valves and piping. The cylinders were securely fastened to the body and frame of the vehicle to insure safe transportation. Each cylinder was piped directly to the analyzer for ease of operation.

The sample gases were pumped to the van from four separate probes. While one sample was being monitored, the other three were vented from the van to insure that a fresh sample would be available when required. This operation was performed automatically by the sample timer.

The gases were analyzed as received at the 35°F dew point except for the NO instrument which had twin chemical driers for the removal of water. The driers were filled with fresh indicating drierite before each run and were only used until the color change had reached the mid-point of the tubes.

The hydrocarbon instrument, a Beckman Model 400 flame ionization detector, measured only the hydrocarbons that reach the instrument. Only hydrocarbons volatile under the sampling conditions could be measured by this instrument because of the sample preparation system. The initial filtration 300-500°F removed solid as well as liquid particulates. The glass wool packed column, maintained at 250°-300°F, might have removed lower boiling liquids. Gases were then refrigerated to a 35°F dew point before being analyzed for hydrocarbons. The condensate from the refrigeration unit was analyzed for organic carbon in selected test runs, and was found to contain on the average 20-30 ppm hydrocarbon equivalent in the flue gas.

In addition to the recorders in the van, separate trend recorders for NO, O_2 and CO were provided for remote observation of flue gas concentrations in the control room of the utility. The effects of changes in operating variables, therefore, were continuously displayed to provide information to the operating personnel in the control room.

While in most cases the instruments performed satisfactorily, some special problems did arise. The CO instrument, which has a long path infrared cell, was found to be sensitive to 200 ppm CO full scale. Moisture interference was a major problem for this long path instrument. Changes were made in the filter cells, heater circuits, and in the gold coating of the sample cell. These changes reduced the problem but could not completely eliminate it. Although this problem may be circumvented by using chemical driers upstream of the sample cell, a more satisfactory solution is desirable for future measurements of this type. Narrow band-path optical filters will be installed to reduce moisture interference with the response of the sample cell.

The NO_2 instrument, a non-dispersive ultraviolet analyzer, was designed for 100 ppm NO_2 full scale. However, the accuracy of measuring extremely small amounts of NO_2 in the flue gases was affected by the noise level of the instrument. This noise level was substantially increased by the remote location of the NO_2 instrument, and the varying temperature environment.

Our experience demonstrated that with the NO_2 analyzer (an instrument designed for a laboratory environment) even though it was shock mounted for vibration, the sensitivity of the mirror adjustment was such that we lost calibration during runs due to boiler-induced and other vibrations of very low frequency. Also, because this instrument was used for measuring hot samples of the corrosive flue gas which had not been subjected to condensation, the analyzer was fouled easily. Small temperature variations due to the wind-chill factor at unprotected outside boiler locations could cause condensation in the analyzer. Then, an elaborate cleaning procedure was required, which could not be performed during actual testing. Based on these findings, our future plans are to redesign this portion of the analytical system.

Integration of Sampling-Analytical System into Mobile Van

The van used to house the instruments, sampling train, and wet chemical laboratory is a Winnebago mobile home shell. The basis for the selection was availability, allowable payload weight and a self-contained propulsion system to provide maximum mobility. The shell is 27 feet long by 7 feet 6 inches wide and is mounted on a Dodge truck chasses. The driver compartment is located in the first 5 feet of the shell. The van is air conditioned and heated for all-weather operation. A gasoline-powered electric generator housed in a compartment of the chassis provides power for lighting and air conditioning during the initial equipment deployment. However, during sampling and data collection the van operated with electricity provided at the generating station. A floor plan of the van is presented in Figure E-2.

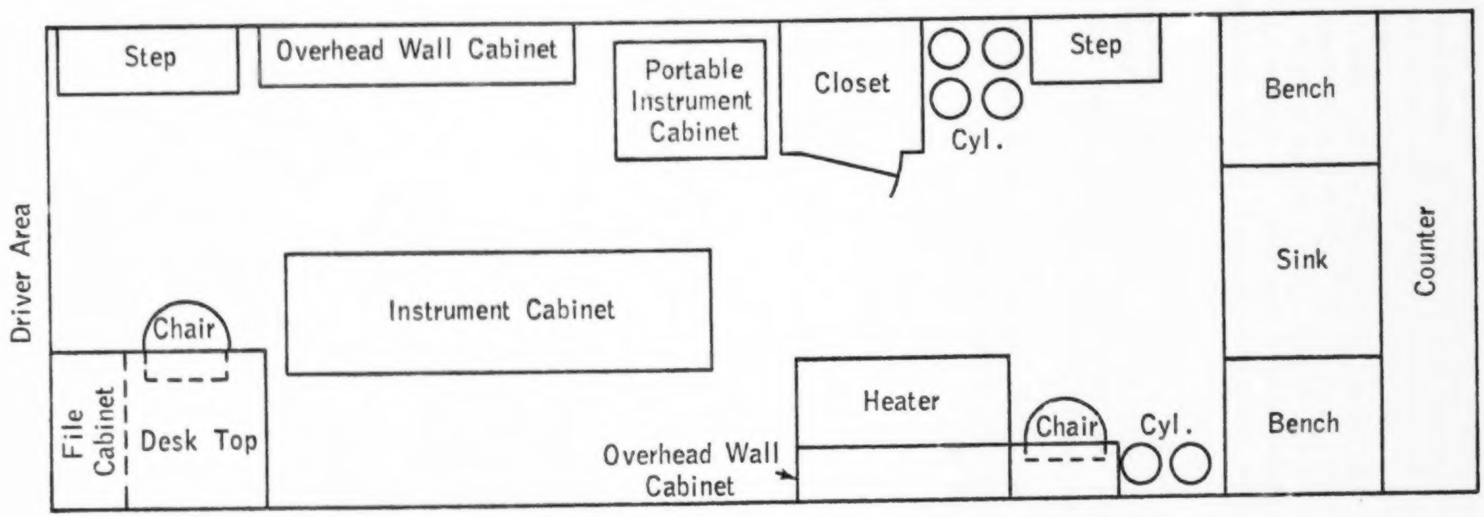
Step
Overhead Wall Cabinet
Portable Instrument Cabinet
Closet
Cyl.
Step
Bench
Sink
Counter
Bench
Driver Area
Chair
File Cabinet
Desk Top
Instrument Cabinet
Heater
Overhead Wall Cabinet
Chair
Cyl.

FIGURE E-2 FLOOR PLAN OF SAMPLING-ANALYTICAL VAN

The instruments are housed in a permanent shock mounted instrument console. The calibration gases are permanently installed in the rear of the van. These cylinders are securely mounted for traveling and each bottle has its own low pressure safety valve and velocity check in addition to standard regulators and valves. The rear of the van is designed as a laboratory bench including a sink. It is used for experimentation and as a foul weather workbench. A swingaway desk top and a file cabinet provide an area for data analysis inside the van. A Sony programmable desk calculator for preliminary data reduction is part of the equipment carried in the van.

An electrical distribution center for the van includes voltage regulators ahead of the instrumentation to anticipate any large variations in line voltage between generating stations. Normal power requirements are 14 KVA for the van and the remote sampling train.

The van holds its own water supply and has a portable winch for equipment deployment. The external connections to the van are all quick disconnects in an umbilical area.